U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-254 308

Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Ind.

Temple, Barker & Sloane, Inc.

Prepared For
Environmental Protection Agency

May 1976

KEEP UP TO DATE

Between the time you ordered this report—which is only one of the hundreds of thousands in the NTIS information collection available to you—and the time you are reading this message, several *new* reports relevant to your interests probably have entered the collection.

Subscribe to the **Weekly Government Abstracts** series that will bring you summaries of new reports *as soon as they are received by NTIS* from the originators of the research. The WGA's are an NTIS weekly newsletter service covering the most recent research findings in 25 areas of industrial, technological, and sociological interest—invaluable information for executives and professionals who must keep up to date.

The executive and professional information service provided by NTIS in the **Weekly Government Abstracts** newsletters will give you thorough and comprehensive coverage of government-conducted or sponsored research activities. And you'll get this important information within two weeks of the time it's released by originating agencies.

WGA newsletters are computer produced and electronically photocomposed to slash the time gap between the release of a report and its availability. You can learn about technical innovations immediately—and use them in the most meaningful and productive ways possible for your organization. Please request NTIS-PR-205/PCW for more information.

The weekly newsletter series will keep you current. But *learn what you have missed in the past* by ordering a computer **NTISearch** of all the research reports in your area of interest, dating as far back as 1964, if you wish. Please request NTIS-PR-186/PCN for more information.

WRITE: Managing Editor
5285 Port Royal Road
Springfield, VA 22161

Keep Up To Date With SRIM

SRIM (Selected Research in Microfiche) provides you with regular, automatic distribution of the complete texts of NTIS research reports *only* in the subject areas you select. SRIM covers almost all Government research reports by subject area and/or the originating Federal or local government agency. You may subscribe by any category or subcategory of our WGA **(Weekly Government Abstracts)** or **Government Reports Announcements and Index** categories, or to the reports issued by a particular agency such as the Department of Defense, Federal Energy Administration, or Environmental Protection Agency. Other options that will give you greater selectivity are available on request.

The cost of SRIM service is only 45¢ domestic (60¢ foreign) for each complete microfiched report. Your SRIM service begins as soon as your order is received and processed and you will receive biweekly shipments thereafter. If you wish, your service will be backdated to furnish you microfiche of reports issued earlier.

Because of contractual arrangements with several Special Technology Groups, not all NTIS reports are distributed in the SRIM program. You will receive a notice in your microfiche shipments identifying the exceptionally priced reports not available through SRIM.

A deposit account with NTIS is required before this service can be initiated. If you have specific questions concerning this service, please call (703) 451-1558, or write NTIS, attention SRIM Product Manager.

This information product distributed by

NTIS U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161

181219

EPA-230/3-76-013

PB 254 308

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

TECHNICAL REPORT

prepared for

ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF PLANNING & EVALUATION

by

TEMPLE, BARKER & SLOANE, INC.
15 WALNUT STREET
WELLESLEY HILLS, MASSACHUSETTS 02181

MAY 1976

REPRODUCED BY
NATIONAL TECHNICAL INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

BIBLIOGRAPHIC DATA SHEET

1. Report No. EPA 230/3-76-013

2.

3. Recipient's Accession No. PB254308

4. Title and Subtitle Economic and Financial Impact of Federal Air and Water Pollution Controls on the Electric Utility Industry - Technical Report

5. Report Date May 1976 Date Issued

6.

7. Author(s) Temple, Barker and Sloane, Incorporated

8. Performing Organization Rept. No.

9. Performing Organization Name and Address

Temple, Barker and Sloane, Incorporated
15 Walnut Street
Wellesley Hills, Massachusetts 02181

10. Project/Task/Work Unit No.

11. Contract/Grant No. 68/01/2803

12. Sponsoring Organization Name and Address

Office of Planning and Evaluation
Environmental Protection Agency
401 M Street, S.W.
Washington, D.C. 20460

13. Type of Report & Period Covered Final

14.

15. Supplementary Notes

16. Abstracts The study focused on the determination of changes in the financial profile of the electric utility industry which are likely to result from federal air and water pollution controls for the 1975-1990 period. The analysis provides operating and financial projections at the national and regional levels as well as a detailed discussion of the financing needs and problems of the industry in the context of trends and cycles in corporate business financing. In addition, the study includes an analysis of the secondary impacts of the legislation on major industrial users of electricity. The research effort concluded that capital expenditures for plants in service will increase by $25.0 billion (1975 dollars) during the 1975-1985 period, of which $19.3 billion must be raised in the capital markets. The direct impact of the regulations upon the average residential customer's electric bill will be an increase of $2.80 per month by 1985 (1975 dollars). Assuming the industry is able to pass on the costs of pollution control equipment to its customers and offer investors a competitive return on equity (approximately 14 percent), the industry will generally be able to obtain the financing required. The study contains two parts: the first is an executive summary, bound separately; the second is a six-volume technical report which includes all methodological and analytical detail.

17. Key Words and Document Analysis. 17a. Descriptors

17b. Identifiers/Open-Ended Terms

17c. COSATI Field/Group

PRICES SUBJECT TO CHANGE

18. Availability Statement Release Unlimited

19. Security Class (This Report) UNCLASSIFIED

20. Security Class (This Page) UNCLASSIFIED

21. No. of Pages 515

22. Price $12.75-225

FORM NTIS-35 (REV. 10-73) ENDORSED BY ANSI AND UNESCO. THIS FORM MAY BE REPRODUCED USCOMM-DC 8265-P74

FOREWORD

This report is the result of a major program of studies sponsored by the Environmental Protection Agency as part of its continuing effort to assess the economic impacts of its regulatory programs. Unlike many of EPA's other industry economic studies where the focus is on the impact of a particular regulation, this study was aimed at examining the combined effect of all of EPA's direct regulatory programs on the electric utility industry. This was an ambitious objective and in some instances it was not possible to take every regulation into account due to the lack of data or the absence of final regulations; however, it was possible to focus quantitatively on the most significant programs, primarily those dealing with air and water pollution control.

In addition to providing an assessment of the combined impact of EPA's regulatory programs, a major objective of this study was to advance the methodologies used in previous studies so as to provide more accurate conclusions as well as provide a better foundation for future studies. This was done in many cases by making use of more up-to-date or previously unused data in areas such as industry production cost and pollution control cost. However, advances also may have been made in the basic analytical techniques used for impact analysis.

In sponsoring this study the EPA wanted to make an independent assessment of the electric utility industry. Although the overall conclusions are endorsed by the Agency, there may be instances in which technical judgments of the contractor differ from those of the EPA. Similarly, assumptions used in the study that are of a policy nature should not be construed as an indication of EPA policy intentions.

This report was prepared for EPA by Temple, Barker & Sloane, Inc. of Wellesley Hills, Massachusetts under contract number 68-01-2803. Additional copies are available through the National Technical Information Service, Springfield, Virginia 22151. Further information concerning this and other economic studies conducted by EPA can be obtained through the Office of Planning and Evaluation, U.S. Environmental Protection Agency.

TABLE OF CONTENTS

TECHNICAL REPORT

Page

Preface (ix)

Structure of the Report (xi)

VOL. I CHARACTERIZATION OF THE ELECTRIC UTILITY INDUSTRY DURING 1960-1975

- 1960-1965: Security and Prosperity I-3
- 1966-1973: Uncertainty and Adversity I-6
- 1974: The Nadir? I-12

VOL. II NATIONAL BASELINE PROJECTIONS

1 INTRODUCTION AND SUMMARY OF BASELINE CASE FINANCIAL PROJECTIONS FOR THE ELECTRIC UTILITY INDUSTRY II-1

- Approach II-1
- Summary of Baseline Case Financial Projections II-4
- Comparison with Alternative Scenarios II-8

2 BASELINE DEMAND PROJECTIONS II-13

3 BASELINE CAPACITY AND GENERATION PROJECTIONS II-18

- Capacity II-19
- Capacity Factors and Generation II-30

4 COST FACTORS II-33

- Capital Cost Factors II-33
- Operating and Maintenance Cost Factors II-37

Preceding page blank

Page

5 FINANCIAL POLICIES AND COSTS II-42
Industry Structure II-42
Capital Structure and Capital Costs II-43
Accounting Practices II-45
Taxes II-46

VOL. III NATIONAL FINANCIAL IMPACTS

1 INTRODUCTION AND CONCLUSIONS III-1

2 HISTORY OF THE REGULATIONS AND AMOUNT OF CAPACITY AFFECTED III-4
History of the Clean Air Act Regulations III-4
History of Federal Water Pollution Control Regulations III-7
Capacity Impacted by Federal Air and Water Regulations III-8

3 CAPITAL EXPENDITURES IMPACTS OF AIR AND WATER REGULATIONS III-20
Capital Expenditures by Regulation III-20
Timing of Capital Expenditure Requirements III-22
Capital Expenditures by Type of Pollution Control Equipment III-23
Capital Expenditures to Make up Capacity Losses III-26
Other Air Regulations III-28

4 OTHER FINANCIAL AND ENERGY IMPACTS III-32
External Financing Requirements III-32
Operation and Maintenance Costs III-34
Operating Revenues and Consumer Charges Impacts III-35

Page

Impact on the Average Residential Bill for Electricity III-36

Energy Impacts III-39

5 ASSUMPTIONS FOR ANALYSIS OF THE AIR REGULATIONS III-42

Capacity Affected by the Regulations III-43

Capital Costs III-48

Operation and Maintenance Costs III-50

Capacity Loss/Energy Penalty III-51

Financing III-52

6 ASSUMPTIONS FOR ANALYSIS OF WATER REGULATIONS III-53

Capacity Affected III-55

Capital and Operation and Maintenance Cost Estimates III-65

7 COMPARISON OF CURRENT ANALYSIS OF WATER REGULATIONS AND DECEMBER 1974 RESULTS III-70

VOL. IV FINANCING IN CAPITAL MARKETS

1 INTRODUCTION AND SUMMARY CONCLUSIONS CONCERNING ELECTRIC UTILITY FINANCING IV-1

Introduction IV-1

Summary Conclusions IV-2

2 RECENT TRENDS AND CYCLES IN CORPORATE BUSINESS FINANCING IV-6

The Need for Corporate Financing IV-7

Corporate Sources of Funds IV-9

Inflation and the Need for External Funds IV-11

External Funds Raised in Financial Markets IV-13

The Cyclical Patterns of External Funds IV-14

Page

The Changing Corporate Balance Sheet IV-15

Corporate External Funds Within The Financial System IV-16

Corporate Financing in 1975 IV-18

3 FUTURE PROJECTIONS OF CORPORATE FINANCIAL NEEDS IV-19

The Determinants of External Financing IV-19

Three Alternative Scenarios for 1975-1985 IV-22

Corporate External Needs in Competition with Other Sectors of the Economy IV-26

The Supply and Demand for Funds in Three Alternative Scenarios IV-29

Variations Within a Credit Cycle IV-34

Conclusions IV-34

4 ELECTRIC UTILITY INDUSTRY FINANCIAL RESULTS AND FINANCING, 1960-1975 IV-36

1960-1965: Growth and Prosperity IV-36

1966-1973: Growth Without Prosperity IV-40

1974: Financial Nadir? IV-48

1975 IV-52

5 PROJECTIONS OF ELECTRIC UTILITY INDUSTRY FINANCING, 1975-1985 IV-54

The Industry's Financing Requirements IV-54

Investor-Owned Electric Utility Needs Versus Available Funds and Total Corporate Needs IV-55

Projected Financial Strength of Investor-Owned Utilities IV-60

Concluding Comments IV-66

Page

6 FINANCING PROBLEMS OF INDIVIDUAL SYSTEMS IV-68
Three Categories of Financial Health IV-68
Intercompany Comparisons of Returns and Interest Coverage IV-71
Determinants of Interest Coverage Ratios IV-75
Conclusions Concerning Electric Utility Financing Problems IV-78

VOL. V REGIONAL IMPACT PROJECTIONS

1 INTRODUCTION AND SUMMARY OF REGIONAL IMPACT PROJECTIONS V-1

2 REGIONAL BASELINE PROJECTIONS V-5
Operating Projections V-7
Financial Projections V-12

3 REGIONAL POLLUTION CONTROL IMPACTS V-19
Methodology V-19
Impact of Pollution Control Compliance Measured by Consumer Charges V-21
Impacts Projected Region by Region V-23
Summary of Regional Capital Expenditures and Operating and Maintenance Expenses V-41

VOL. VI SECONDARY IMPACTS

1 INTRODUCTION AND OVERALL CONCLUSION VI-1
Introduction VI-1
Overall Conclusion VI-1

2 IMPACTS ON THE MAJOR USERS OF ELECTRICITY VI-4
Methodology VI-5
Major Assumptions VI-8
Possible Refinement VI-10

Page

3 IMPACTS UPON THE U.S. SULFUR INDUSTRY AND ADDITIONAL SECONDARY IMPACTS VI-12

Sulfur Industry VI-12

Other Areas VI-26

PREFACE

This report has been submitted to the Environmental Protection Agency in fulfillment of contract No. 68-01-2803 by Temple, Barker & Sloane, Inc., 15 Walnut Street, Wellesley Hills, Massachusetts.

The research methodology employed in this study is based on a computerized Policy-Testing model (PTm) of the electric utility industry. This model is one of a series of industry models developed by Temple, Barker & Sloane, Inc. (TBS) to project the economic and financial implications of alternative policy options in the form of industry structure, rates and method of expansion, financial strategies, regulatory actions, taxation policy, economic conditions, etc. PTm(Electric Utilities) was initially developed by Drs. Howard W. Pifer and Michael L. Tennican, both of TBS, to assist the National Power Survey's Technical Advisory Committee on Finance in preparing its projections. It later served as the methodology for the Environmental Protection Agency's evaluation of the economic impact of its effluent guidelines upon the electric utility industry.

TBS wishes to express its gratitude to the many organizations and individuals who contributed to this study. The work has benefited from the cooperation of the industry's Clean Air Coordinating Committee and its predecessor, the Utility Water Act Group. The comments of the many people in EPA, other Agencies, and the industry who reviewed the earlier versions of this report have also made a substantial contribution to this final product. Particular thanks is due to our project managers at EPA, James M. Speyer and James R. Ferry, for the special efforts they also put into the study.

STRUCTURE OF THE REPORT

The scope of this study spans several aspects of the general topic: the economic and financial impacts of federal pollution control regulations on the electric utility industry. Each major study area has become the subject of a separate volume in order to segment the report into logical, manageable pieces. The definition of the volumes and their sequence in the report also reflect the TBS study approach. The Executive Summary to the report has been printed under separate cover. The volumes in this document are:

Volume I.	An historical overview of the electric utility industry during the past fifteen years, in order to provide a context in which to consider the projections into the future.
Volume II.	The baseline projections (1975-1985) for the industry before consideration of pollution control expenditures, to establish a basis for estimating and evaluating future impacts.
Volume III.	The direct economic and financial impacts of pollution control on the electric utility industry, in terms of capital expenditures, external financing, operating expenses, and so on.
Volume IV.	The ability of the industry to obtain the capital financing identified in Volume III from the nation's capital markets.
Volume V.	The regional variations in the direct impacts of pollution control in the industry.
Volume VI.	The extent of secondary impacts resulting from the increased costs and the operation of pollution control equipment in the industry.

Preceding page blank

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

VOLUME I

CHARACTERIZATION OF THE ELECTRIC UTILITY INDUSTRY DURING 1960-1975

MAY 1976

VOLUME I

TABLE OF CONTENTS

Page

List of Exhibits (I-iii)

1960-1965: Security and Prosperity I-3

1966-1973: Uncertainty and Adversity I-6

1974: The Nadir? I-12

VOLUME I

LIST OF EXHIBITS

Exhibit

I-1 Annual Growth in Peak Demand and Energy Sales; Total Electric Utility Industry, 1960-1973

I-2 Selected Demand, Energy, and Capacity Statistics; Total Electric Utility Industry, 1960-1974

I-3 Cost Per Kilowatt of Capacity--Newly Constructed Plants; Total Electric Utility Industry, 1960-1974

I-4 Average Industry Heat Rates; Total Electric Utility Industry, 1960-1974

I-5 Average Industry Fuel Cost Per Million Btu; Total Electric Utility Industry, 1960-1974

I-6 Cost Per Kilowatt-Hour; Privately Owned Class A&B Electric Utilities in the United States; Electric Department, 1960-1973

I-7 Average Residential Bills and Overall Average Revenue Per Kilowatt-Hour; Total Electric Utility Industry, 1960-1973

I-8 Number of Customers and Average Kilowatt-Hour Usage Per Customer; Total Electric Utility Industry, 1960-1973

I-9 Assets Per Dollar of Revenue; Privately Owned Class A&B Electric Utilities in the United States; Electric Department, 1960-1973

Preceding page blank

VOLUME I

CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY DURING 1960-1975

This volume briefly describes the changing characteristics of the electric utility industry from 1960 to 1975. This volume is intended as background for the projections and analyses of the later volumes of this study.

Electrical energy is of major importance to the U.S. economy. The use of energy in all forms in the United States grew at an annual rate of 4.4 percent from 1960 to 1973. During the same period, the use of electrical energy grew at an annual rate of 7.3 percent. By 1974, electricity accounted for approximately 23 percent of all energy used in the country, up from 16 percent in 1960.

The sheer scale of the electric utility industry causes its activities to be of major importance and concern. The industry has large revenues: Investor-owned utilities, which account for about 78 percent of total electric sales to final consumers, had revenues of roughly $35 billion in 1974. However, the industry is distinguished particularly by its extremely high plant investment per dollar of revenue. Total investor-owned electric utility assets, excluding the natural gas assets held by combination gas and electric companies, reached over $143 billion in 1974. Moreover, an increasing portion of the industry's large annual capital expenditures, over $16 billion in 1974, in recent years has been financed from external sources.

Although most of the published commentaries on the industry focus on investor-owned companies, the electric utility industry also comprises publicly-owned and cooperative systems.

In number, almost two-thirds of the 3,500 separate electrical systems in the United States are publicly owned. A few of the federal and state systems--such as the Bonneville Power Authority, the Tennessee Valley Authority, and the County Public Utility Districts in the state of Washington--generate enormous amounts of electricity and are, in fact, large suppliers to investor-owned systems. However, most of the publicly-owned and cooperative systems in the country are small entities engaged in distribution only. In contrast, the approximately 500 investor-owned companies account for nearly 79 percent of the generating capacity, total assets, and electrical generation. Publicly-owned systems have nearly a 20 percent share of capacity, assets, and generation. Cooperative systems account for under 2 percent of capacity, assets, and sales. There has been a slight shift toward investor-owned and cooperative and away from publicly-owned utilities over the past fifteen years, but this change has been very small.

In this report, the historical analysis will focus primarily on the investor-owned systems, for which data are readily available. The projections of future industry capital expenditures and financing needs will, however, cover all sectors of the industry and are presented in Volumes II and III of this report. The access to and the costs of financing differ, of course, across public and private firms. The potential problems of the investor-owned utilities in raising capital in the future will be of primary concern in Volume IV.

Until the mid 1960s, the electric utility industry had enjoyed a record of steady and predictable growth. In the latter half of the 1960s, however, a multiplicity of changes began to upset the industry's dependable historical trends, and uncertainty began to envelop the entire process of decision making in the electric utility industry.

The result of this uncertainty was an end to both predictability and relatively secure decision making. In their place has come genuine concern over the most appropriate way to meet the demands and challenges now facing the industry.

1960-1965: SECURITY AND PROSPERITY

The early 1960s was a period of decreasing costs of electrical energy, of increasing electricity consumption, and of general prosperity for the electric utility industry. The yearly growth in kilowatt-hour sales during the 1960-1965 period ranged narrowly between 5.5 percent and 7.7 percent, averaging 6.9 percent (Exhibit I-1). The industry's growth in peak demand, and hence in its need for capacity, was similar, as is also shown in Exhibit I-1. Thus, despite construction lead times of several years for new generation capacity, the industry could predict future demand well enough so as to be assured of meeting that demand without having to build large amounts of excess capacity. At the company level there was, of course, more variability in demand, but even there much of the variation was the result of relatively predictable factors such as the growth in population, the growth in industrial activity, and the like.

Evolutionary technical changes in the design and operating performance of generation equipment took place during this period. (Nuclear technology was on the horizon, but few substantial orders were placed until 1965.) The changes mostly took the form of increasing unit size and increasing operating pressures and temperatures, which enabled scale efficiencies in construction and decreased heat rates in operation.[1] The declining trend in costs per kilowatt of capacity over this period is shown in Exhibit I-3.

Because of the industry's rapid growth, which in turn was stimulated by the declining real price of electrical energy, the newer equipment rapidly accounted for a major proportion of the industry's total generation capacity. Thus, the design advantages of the new capacity, coupled with declining fuel costs, enabled the industry to hold constant or reduce fuel and other generation costs and generation-related depreciation charges per kilowatt hour despite general price level increases (see Exhibit I-6).[2]

Exhibit I-6 also shows that during this period transmission expenses, distribution expenses, general selling and administrative costs, and taxes also trended downward. The operations and maintenance cost decreases reflect the net effect of a variety of factors, including technological improvements and increasing electrical consumption per customer. What is most important is that the industry's total cost per kilowatt-hour declined significantly from 1960 to 1965.

Because of regulatory controls on the industry's earnings, the industry's declining costs were accompanied by almost commensurate declines in the average prices paid by consumers (see Exhibit I-7). It should be noted that the cost of any given amount of consumption declined only slightly, as is shown in Exhibit I-7. However, to promote the use of electricity and reflect the relatively low incremental costs of supplying more energy to a typical customer,[3] the industry's price structure reflected substantial decreases in the price per kilowatt-hour with increasing amounts of consumption per period. As a result, as consumption per customer increased (see Exhibit I-8), average revenues per kilowatt-hour decreased.

---

[1] *Heat rate, a measure of a generating station's efficiency in converting thermal energy to electric energy, is the number of British thermal units in the fuel required to generate one kilowatt hour.*

[2] *The data in this exhibit and all subsequent references to balance sheet and income statement items show adjustments by TBS to reflect only the electric operations of combination gas and electric companies.*

Because increases in the numbers of customers (extensive growth) and increases in the average kilowatt hour usage per customer (intensive growth) more than offset declines in revenues per kilowatt hour, the industry's total revenues grew at a rate of 5.8 percent from 1960 to 1965, or from $10.1 billion to $13.4 billion (Exhibit I-9). As shown in Exhibit I-8, the number of customers grew at a rate of 2.2 percent from 1960 to 1965, while the kilowatt-hours sold per customer grew at a rate of 4.6 percent per year, far outweighing the 1.2 percent decline experienced in revenues per kilowatt-hour (Exhibit I-7).

These years were good ones for the electric utility industry: problems were predictable and manageable, uncertainty was at a minimum, and all the factors underlying prosperity were operating in favor of the industry.[4] These years also were good ones for consumers of electricity because the price per kilowatt-hour was declining. All that would change, but few anticipated that from the vantage point of the early 1960s.

---

[3] *Customers whose increased energy consumption came at the time of a utility's peak demand would, of course, receive high incremental costs. For a discussion of the costs of service as a function of a customer's time profile of consumption, the supplying system's demand profile, etc., see, for example, TBS's study for the Federal Energy Administration, A Study of Electric Utility Costs, Demand, and Rate Structures, 1975*

1966-1973: UNCERTAINTY AND ADVERSITY

Beginning in 1966, a number of adverse changes occurred which had severely affected the industry's situation by the end of 1973. The prosperous and predictable nature of the electric utility industry changed for the worse; relative certainty was replaced by uncertainty and a difficult environment. The changes affecting the industry did not happen all at once and did not stem from the same root. Rather, the industry was beset over a relatively brief period of time with trends which were gaining momentum in the last half of the decade. Five of these were to have a dramatic and disastrous effect on the industry as it moved into the 1970s.

The Credit Crunch

While it can be argued that the cost of money was destined to go up anyway as the economy began to overheat in the late 1960s, the credit crunch of 1966 caused a dramatic rise in the cost of money. As an example, Moody's industrial bond rate, which by 1965 had remained virtually constant for seven years, rose steadily from 1966 until, in 1970, the bond rate was almost double what it had been five years earlier. The cost--and ultimately the availability--of debt had obvious implications for the electric utility industry.

---

[4] *Earnings, capital expenditures, cash flow, and financing considerations are discussed in detail in Chapter 4 of Volume IV, "Electric Utility Industry Financial Results and Financing."*

Inflation

Chronic inflation had been an irritant in the economy for some time, but by the late 1960s the rate of cost increases for most companies was outrunning productivity gains. Most important for electric utilities, inflation was particularly felt in the capital goods industries, thereby increasing the cost of building new utility plants--an event destined to have a significant effect on the utility companies.

Equipment Shortages

Parts and equipment shortages began to appear during the second half of the 1960s. Much of this was due to capacity shortages in an overheated economy. The result for the electric utility industry was delays in new plant construction, with the attendant higher ultimate costs that such delays invariably bring: higher capital costs because projects required longer financing prior to being placed in service, and higher interim operating costs because newer, more efficient plants did not get on stream when expected and utilities were forced to rely on more costly older plants or more expensive purchased power in the meantime.

The Environmental Movement

The momentum of the environmental movement increased greatly in the late 1960s. While it can be argued that the costs of electricity--and hence electric rates--had never reflected true "environmental costs," the impact of this movement was felt in three principal ways. First, it affected the cost of fuel to electric utilities as state and local governments placed sulfur restrictions on fuels. Second, environmental protection hearings caused delays in the construction programs of many utilities, causing higher labor, administrative, and financing costs and slowing down the retirement of older, high-cost generating plants beyond planned dates. Finally, the installation and operation of pollution control equipment aggravated the capital and operating cost problems beginning to afflict the industry.

Fuel Cost Increases

The cost of fuel always has been an important component in the cost of electric power. Until the latter part of the 1960s, cost trends were downward. Productivity improvements in the coal industry, together with an abundant supply of interruptible and off-peak gas, kept the prices of fuel down. Then the cost of all fuels began to rise. The closing of the Suez Canal in 1967 caused tanker rates to increase, and at about the same time the oil exporting countries began upward revisions in both posted prices and taxes. The result, of course, was higher-priced oil. The price of coal also began to increase, spurred by the rise in the price of oil and also by the need for investment to improve health and safety conditions and by the rise in foreign demand for metallurgical coal. Finally, the Federal Power Commission began to permit increases in the price of interstate natural gas. This obviously affected those utilities dependent on that fuel source, but it also relieved the competitive pressure on alternative fuels, thereby allowing the prices of coal and oil to rise.

Thus, the impact of the credit crunch, inflation, equipment shortages, the environmental movement, and fuel cost increases--all events that were emerging in the late 1960s--

combined to change dramatically the prosperous and predictable future of the electric utility industry.

The events of the late 1960s resulted in a significant change in the nature of the electric utility industry. The industry had entered into a period of growth without prosperity--a period, in fact, where growth was responsible for much of the lack of prosperity. The most significant changes occurred in three major areas: the rate of growth in energy usage and in peak demand; the increases in capacity additions and in the unit cost of capacity; and the increases in operating and interest costs.

Energy[5] and Peak Demand

The industry continued to grow in the late 1960s and early 1970s. From 1966 to 1973, the annual growth in demand increased both in level and in uncertainty as compared to the early 1960s. The range in peak demand growth from 1966 to 1973 was from 5.0 percent to 11.5 percent, averaging 8.1 percent. Similarly, energy consumption growth rates ranged from 5.4 percent to 9.0 percent from 1966 through 1973, averaging 7.1 percent (see Exhibit I-1). The increased uncertainty in the electric utility industry's growth was perhaps undramatic compared to the problems of predicting demand in many other industries. The consequence of this level of uncertainty in the electric utility industry was nonetheless important because the construction of the nuclear units then being planned required a lead time of approximately ten years. Even small differences in compound growth rates over such a period result in large differences in projected capacity requirements at the end of the period.

---

[5] *Energy is the total amount of electricity used over a period of time; it is expressed in kilowatt-hours.*

Capacity Additions and Unit Costs

The increased average growth rate of peak demand over the 1966-1973 period increased the rate of capacity additions and consequent capital expenditures. A partial offset was reduced reserve margins in generating capacity resulting, in part because of unanticipated delays, in bringing new capacity into service (see Exhibit I-2). Nonetheless, capital expenditure requirements burgeoned because of the industry's rapid rate of capacity additions and because of rapidly escalating average costs per kilowatt of capacity.

Two factors brought about a dramatic rise in the cost per kilowatt of capacity after 1966. First, fossil-fueled units began to reach a size at which efficiencies of scale diminished or disappeared. Second, the industry began to build nuclear units, which involved higher capital costs and longer construction lead times. Exhibit I-3 highlights the particular problem experienced with nuclear fueled generating units: The cost of these units escalated at spectacular rates. As a consequence, average costs per kilowatt increased substantially--despite the inclusion in these averages of a number of internal combustion peaking units with low capital costs (see Exhibit I-3).

Operating and Interest Costs

The industry was able to maintain relatively constant operating costs per kilowatt-hour over the entire decade of the 1960s, but this trend turned around abruptly in 1970 (Exhibit I-6). Until 1970, economies of scale and technological improvements permitted the industry to reduce or to hold constant generation, transmission, and distribution operations, and maintenance costs other than fuel costs. Fuel costs per Btu declined or held relatively constant as coal productivity increased and as users of coal with high transportation costs switched to cleaner and often lower cost residual oil. In addition, the ceiling on natural gas prices imposed by the Federal Power Commission (FPC) held this fuel at a very low cost. (See Exhibit I-5 for fuel cost trends.) Finally, because of accelerated depreciation and investment tax credits, income taxes decreased over the decade. (See Exhibit I-6 for more detail.) In 1970, however, surging fuel costs and general inflationary pressures increased the cost per kilowatt-hour for the first time since World War II. Moreover, as is shown in Exhibit I-4, no longer did decreasing heat rates help offset the effect of higher basic fuel costs. Thus, from 1969 to 1972, the escalation in total costs per kilowatt-hour was quite rapid, rising from 1.49 cents to 1.73 cents per kilowatt-hour.

Interest costs also grew rapidly during the 1966-1973 period, from $903 million in 1966 to $3.15 billion in 1973. This increase reflected the combined impact of two factors: first, much higher interest on new debt issues than the rates on outstanding debt; and second, substantial increases in the industry's volume of outstanding debt.

Thus, several factors had turned against the industry by 1973 and created a financial dilemma: prosperity no longer automatically accompanied growth, and financing growth in a way equitable to investors and consumers alike became a critical issue. The year 1974 offered no solutions.

1974: THE NADIR?

The electric utility industry data for 1974 make it painfully clear that the ill winds of the previous several years blew with hurricane force in 1974. Bludgeoned by the quantum increases in most fossil fuel prices following the Arab oil embargo in late 1973, exhorted by government and industry officials to conserve energy, and perhaps mindful of the accelerating problems of the U.S. economy, consumers held their use of electrical energy to levels almost identical to those of 1973. In fact, usage per customer declined in 1974. Total residential consumption increased only 0.1 percent, total commercial usage dropped 1.1 percent, and total industrial sales grew only 0.3 percent.[6] The industry's rate of growth in summer peak demand also declined sharply to 1.6 percent, but not enough to avoid a decline in the industry's load factor.[7] As a consequence, although a few forecasters held tenaciously to the belief that the industry's growth rate in energy and demand soon would return to its previous track, most members and observers of the industry were left with a pervasive uncertainty concerning the future--a fear that the industry's peak demand would grow more rapidly than its energy output, further reducing load factors.

Capacity additions for 1974 had been determined years before by construction programs--and industry capacity was increased by 7 percent during the year. This new capacity, together with the lack of growth in energy sales, caused a major deterioration in those factors measuring utilization: the industry's reserve margin increased to 27.2 percent from 20.8 percent the year before, and the highest annual reserve margin since 1963; the capacity factor--perhaps the best measure of plant utilization--fell to 48.1 percent from 51.3 percent the year before and held its lowest level in at least 15 years (see Exhibit I-2).

---

[6] *Source and Disposal of Electricity, Volume 42, Edison Electric Institute.*

[7] *Electric Power Survey, Edison Electric Institute, October 1974.*

Operating costs and interest costs also did not fare well in 1974. While the heat rate improved slightly, the cost of fuel increased by a quantum amount. Fuel costs--driven by a more than doubling in the price of oil--reached 89 cents per million Btu, almost doubling the 1973 cost. As a result, total operating costs sustained a sizeable increase--up 45 percent in one year. Similarly, interest charges for the industry increased 28 percent in 1974 from the year before as the embedded interest rate increased from 5.95 percent to 6.38 percent.

As mentioned earlier, net industry capacity increased 7 percent in 1974 over the earlier year. This was accompanied, however, by another large increase in the cost per unit of installed capacity--from $195 to $266 per kilowatt, a 36 percent increase--so the impact on financial requirements and on existing book investments was proportionately larger than the capacity additions of the year before.

Complete data for 1975 are not yet available, but informed estimates provide an indication of what the operating situation may have been for the industry. The highlights of 1975 are outlined below:

- Electricity consumption increased about 2 percent above levels experienced in 1974
- Peak demand increased a "nominal" amount during the year--probably about the same as energy consumption

- Generating capacity increased 7 to 8 percent, implying that additions in 1975 were about the same as in 1974
- Utilization factors fell further in 1975 from the very low levels of 1974
    - The reserve margin probably increased to above 30 percent from the 27.2 percent figure achieved the year before
    - The capacity factor probably fell to below 46 percent from 48.1 percent in 1974
- Operating costs once again increased significantly in 1975
    - Fuel costs--which account for two-thirds of total operating and maintenance costs--reached 102 cents per million Btu, a 15 percent increase over 1974
    - Stringent cost-cutting programs begun in 1974 were continued in 1975, so that operating and maintenance costs (ex-fuel) probably went up less rapidly than wage rates in 1975
- Interest rates for the industry on new long term debt issues declined in 1975 by about three-fourths of a percent.

Thus, both good news and bad news about the industry's operating factors emerged from 1975. Clearly, some of their cost trends either had been reversed or at least had been slowed, and consumption of electrical energy resumed some growth, albeit small. But some major cost trends were still unfavorable, caused in part by low utilization rates.

Exhibit I-1

ANNUAL GROWTH IN PEAK DEMAND AND ENERGY SALES

Total Electric Utility Industry

1960-1973

Years	Growth in Peak Demand of Kilowatts (%)	Growth In Kilowatt-Hour Sales (%)
1960-1961	6.0*	5.5
1961-1962	7.3*	7.7
1962-1963	6.6*	7.1
1963-1964	8.5*	7.2
1964-1965	6.5	7.1
1961-1965 Growth Rate	7.0	6.9
1965-1966	9.2	9.0
1966-1967	5.0	6.5
1967-1968	11.5	8.6
1968-1969	8.3	8.7
1969-1970	6.6	6.4
1970-1971	6.4	5.4
1971-1972	9.3	7.6
1972-1973	7.8	7.9
1966-1973 Growth Rate	8.1	7.1

*In 1960, 1962, and 1963 there was a December non-coincident peak load. Growth is calculated on actual peak and not summer peak of Exhibit 12.

Source: Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, 1973

Exhibit I-2

SELECTED DEMAND, ENERGY, AND CAPACITY STATISTICS

Total Electric Utility Industry

1960-1974

Year	Capacity at Time of Summer Peak Load (MW)	Non-Coincident Summer Peak Load (MW)	Output (KWH in Millions)	Reserve Margin %	Capacity Factor %	Load Factor %*
1960	170,600	132,800	764,900	28.5	51.0	65.6
1961	184,700	141,000	799,800	31.0	49.4	64.8
1962	193,600	149,050	860,200	29.9	50.7	70.1
1963	205,300	159,450	921,800	28.8	51.3	66.0
1964	216,500	175,000	986,800	23.7	51.9	64.2
1965	228,900	186,300	1,060,100	22.9	52.9	65.0
1966	240,700	203,350	1,152,900	18.4	54.7	64.7
1967	257,950	213,450	1,221,500	20.8	54.1	65.3
1968	278,950	238,00	1,327,200	17.2	54.2	63.5
1969	300,300	257,650	1,446,00	16.6	55.0	64.1
1970	326,900	274,650	1,536,400	19.0	53.7	63.9
1971	353,250	292,100	1,617,100	20.9	52.3	68.2
1972	381,700	319,150	1,752,200	19.6	52.3	62.5
1973	415,500	343,900	1,868,800	20.8	51.3	62.0
1974	444.400	349.250	1,871.700	27.2	48.1	61.2

$$\text{*Load Factor} = \frac{\text{Output}}{\text{Non-coincident summer peak load} \times \text{number of hours in the year}}$$

Source: Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, Table 6S, 1973.

Exhibit I-3

COST PER KILOWATT OF CAPACITY--NEWLY CONSTRUCTED PLANTS
Total Electric Utility Industry
1960-1974

Year	In-Service Cost All Plants	In-Service Cost Nuclear Plants	Estimated Cost as of Order Date, Nuclear Plants *	Revised Cost Estimate as of 1974, Nuclear Plants **
1960	$135	$138***	n.a.	n.a.
1961	106	--	n.a.	n.a.
1962	139	410***	n.a.	n.a.
1963	144	382***	n.a.	n.a.
1964	116	--	n.a.	n.a.
1965	109	--	$119	$199
1966	85	--	121	260
1967	118	156	146	354
1968	128	190	157	413
1969	149	213	209	395
1970	141	147	222	370
1971	137	155	300	475
1972	180	183	404	458
1973	195	260	456	456
1974	266	354	558	558
Growth Rate 1966-1974	10.4%	12.4%****	18.7%	12.1%

n.a. = not available

*Cost per KW for nuclear plants estimated at time order placed for all units ordered in the year in table.

**Cost per KW for nuclear plants based on best information available in 1974 for all units ordered in the year in table.

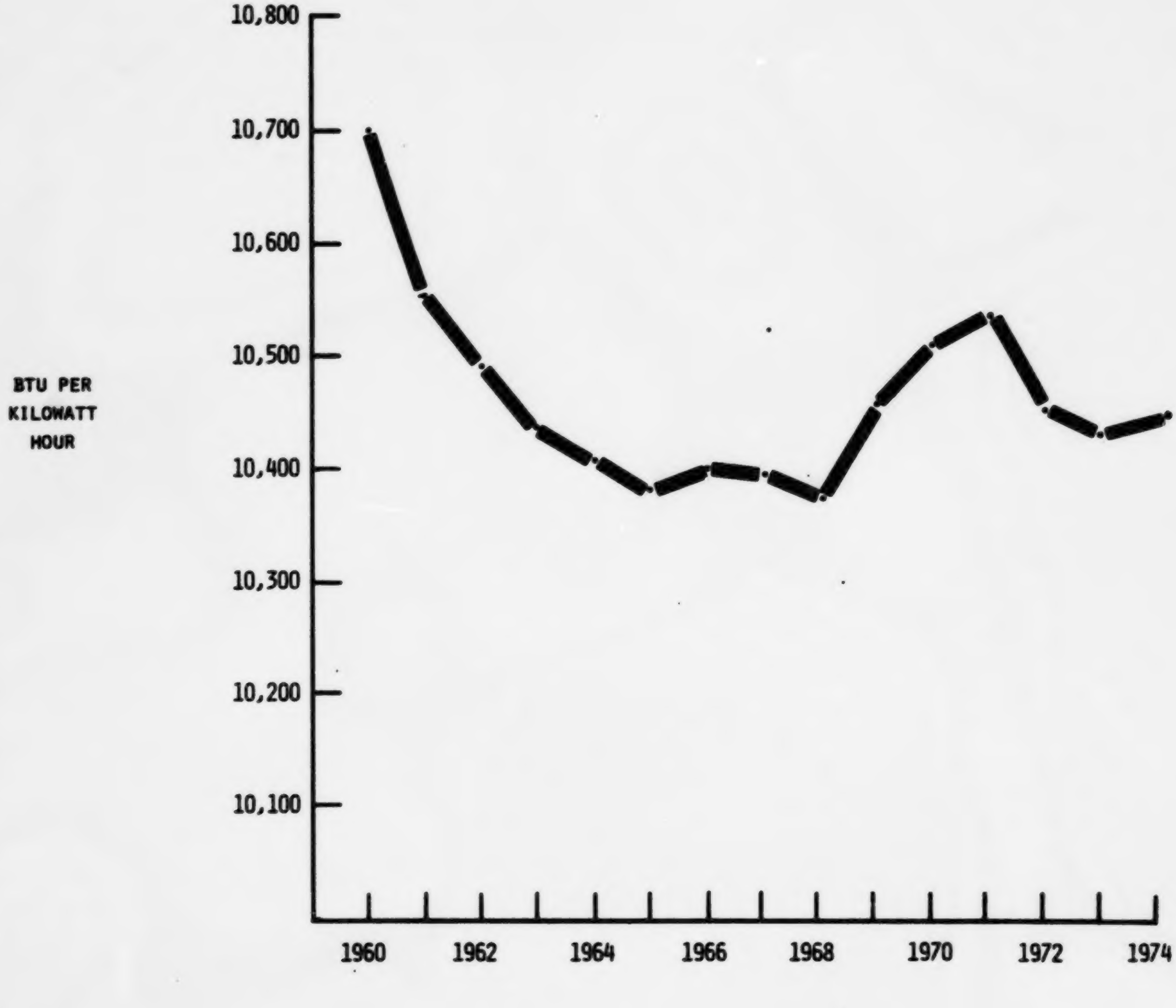
***Based on very small sample

****1968-1974

Source: Steam Electric Plant Construction Cost 1972, Federal Power Commission; Power Engineering (August 1974)

EXHIBIT I-4

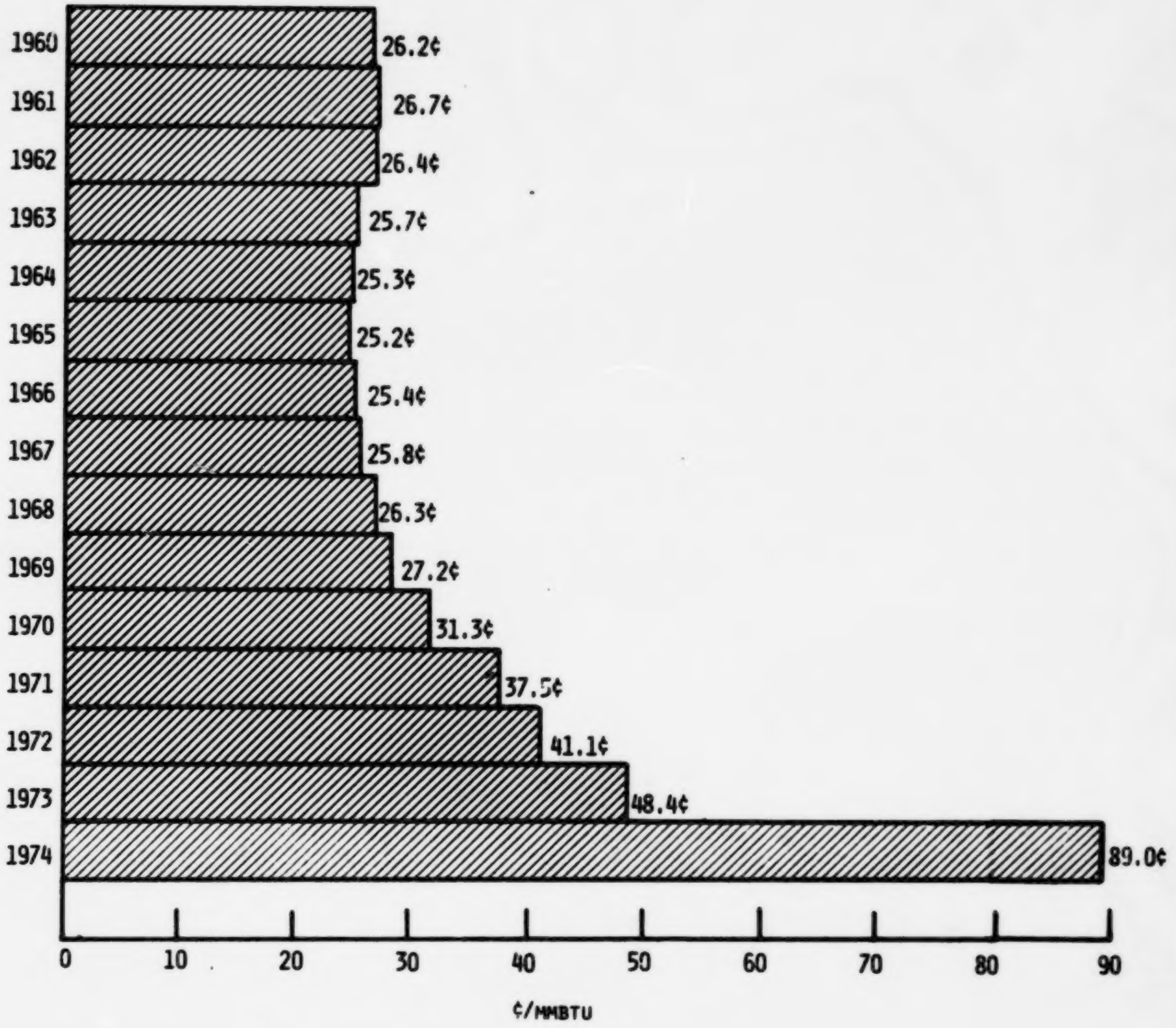
AVERAGE INDUSTRY HEAT RATES
TOTAL ELECTRIC UTILITY INDUSTRY
1960 - 1974



Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry

Exhibit I-5

AVERAGE INDUSTRY FUEL COST PER MILLION BTU
TOTAL ELECTRIC UTILITY INDUSTRY
1960 - 1974



Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry

Exhibit I-6

COST PER KILOWATT-HOUR

Privately Owned Class A&B Electric Utilities in the United States
Electric Department
1960-1973
(cents)

Year	Total Cost	Operating and Maintenance				General Selling & Adminis-tration	Depreciation and Amorti-zation	Non-Income Taxes	AFDC*	Fed. & State Income Tax (Current & Deferred)
		Fuel	Generation	Trans-mission	Distri-bution					
1960	1.63	.29	.19	.03	.15	.21	.21	.20	(.02)	.25
1961	1.63	.29	.19	.03	.14	.21	.21	.19	(.01)	.26
1962	1.60	.29	.19	.03	.13	.21	.21	.19	(.01)	.24
1963	1.57	.28	.19	.03	.13	.21	.21	.19	(.01)	.23
1964	1.54	.28	.19	.03	.13	.20	.21	.19	(.01)	.23
1965	1.51	.27	.19	.02	.12	.20	.21	.18	(.01)	.21
1966	1.49	.28	.19	.02	.12	.19	.20	.18	(.01)	.20
1967	1.48	.28	.20	.02	.12	.18	.20	.19	(.02)	.18
1968	1.48	.29	.20	.02	.11	.18	.20	.19	(.03)	.18
1969	1.49	.30	.21	.03	.11	.18	.20	.19	(.04)	.17
1970	1.55	.35	.22	.03	.12	.18	.20	.20	(.05)	.13
1971	1.65	.41	.25	.03	.12	.19	.21	.21	(.07)	.12
1972	1.72	.44	.26	.03	.12	.19	.21	.21	(.08)	.12
1973	1.84	.50	.29	.03	.12	.19	.22	.22	(.09)	.12

n/a=not available

*Allowance for Funds During Construction prorated by ratio of the change in Gross Electric Plant to the change in Total Gross Plant.

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, and 1973; TBS estimates.

Exhibit I-7

AVERAGE RESIDENTIAL BILLS AND OVERALL AVERAGE REVENUE PER KILOWATT-HOUR

Total Electric Utility Industry

1960-1973

	Average Bill for Residential Service		
Year	**500 kWh**	**250 kWh**	**Revenue Per kWh All Customers**
1960	$10.62	$7.44	1.69¢
1961	10.64	7.45	1.69
1962	10.66	7.48	1.68
1963	10.64	7.48	1.65
1964	10.61	7.43	1.62
1965	10.41	7.38	1.59
1961-1965 Growth Rate	- .4%	- .2%	-1.2%
1966	10.34	7.34	1.56
1967	10.37	7.37	1.56
1968	10.37	7.38	1.55
1969	10.32	7.40	1.54
1970	10.51	7.51	1.59
1966-1970 Growth Rate	+ .2%	+ .4%	0
1971	11.13	7.84	1.69
1972	11.99	8.35	1.77
1973	12.56	8.67	1.86
1971-1973 Growth Rate	+6.1%	+4.9%	+5.4%

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1973; Federal Power Commission, Typical Electric Bills, 1973

Exhibit I-8

NUMBER OF CUSTOMERS AND AVERAGE KILOWATT-HOUR USAGE PER CUSTOMER

Total Electric Utility Industry

1960-1973

Period	Total Customers	kWh Per Customer
1960	58,870,000	11,605
1961	60,130,000	11,986
1962	61,324,000	12,656
1963	62,857,000	13,218
1964	64,148,000	13,880
1965	65,558,000	14,543
1961-1965 Growth Rate	+2.2%	+4.6%
1966	66,910,000	15,528
1967	68,168,000	16,240
1968	69,716,000	17,246
1969	70,929,000	18,429
1970	72,485,000	19,195
1966-1970 Growth Rate	+2.0%	+5.7%
1971	74,265,000	19,746
1972	76,150,000	20,718
1973	78,461,000	21,708
1971-1973 Growth Rate	+2.7%	+4.2%

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1973

Exhibit I-9

ASSETS PER DOLLAR OF REVENUE

Privately Owned Class A&B Electric Utilities in the United States
Electric Department

1960-1973

(1) Year	(2) Gross Electric Plant Investment (millions)	(3) Operating Revenues (millions)	(4) Gross Plant Per Dollar Of Revenue (2)÷(3)
1960	$ 45,456	$ 10,116	$ 4.49
1961	48,090	10,666	4.51
1962	50,699	11,392	4.45
1963	53,474	12,018	4.45
1964	56,326	12,673	4.44
1965	59,703	13,400	4.46
1961-1965 Growth Rate	5.6%	5.8%	--
1966	64,066	14,374	4.46
1967	69,617	15,225	4.57
1968	76,026	16,359	4.65
1969	83,671	18,023	4.64
1970	93,303	19,791	4.71
1971	104,300	22,322	4.67
1972	116,644	25,355	4.60
1973	130,840	29,104	4.50
1966-1973 Growth Rate	10.3%	10.2%	--

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967 1972, and 1973.

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

VOLUME II

NATIONAL BASELINE PROJECTIONS

MAY 1976

VOLUME II

TABLE OF CONTENTS

Page

List of Exhibits (II-iii)

Chapter

1 INTRODUCTION AND SUMMARY OF BASELINE CASE FINANCIAL PROJECTIONS FOR THE ELECTRIC UTILITY INDUSTRY II-1
  Approach II-1
  Summary of Baseline Case Financial Projections II-4
  Comparison with Alternative Scenarios II-8

2 BASELINE DEMAND PROJECTIONS II-13

3 BASELINE CAPACITY AND GENERATION PROJECTIONS II-18
  Capacity II-19
  Capacity Factors and Generation II-30

4 COST FACTORS II-33
  Capital Cost Factors II-33
  Operating and Maintenance Cost Factors II-37

5 FINANCIAL POLICIES AND COSTS II-42
  Industry Structure II-42
  Capital Structure and Capital Costs II-43
  Accounting Practices II-45
  Taxes II-46

Appendix

II-A PTm(ELECTRIC UTILITIES) RESEARCH METHODOLOGY II-75

VOLUME II

LIST OF EXHIBITS

Exhibit	
II-1	PTm Sales and Capacity Assumptions; U.S. Electric Utility Industry (1973-1990)
II-2	PTm Gross Additions to Generating Plant Including Conversions to Coal and Oil (1973-1990)
II-3	PTm Total Generation by Fuel Type Including Conversions to Coal and Oil (1973-1990)
II-4	PTm Total Capacity by Fuel Type (1973-1990)
II-5	PTm Fuels Consumed for Generation of Electricity Conventional Steam and Peaking Units (1973-1990)
II-6	PTm Baseline Financial Projections (1975 dollars)
II-7	PTm Baseline Financial Projections (current dollars)
II-8	Baseline Financial Projections Summary for Selected Years
II-9	Financial Projections of Previous Baseline Conditions
II-10	Financial Projections Summary Based on Previous Load Growth Assumptions and Current Cost Escalation Factors
II-11	Financial Projections Summary Based on Historic Growth Rates
II-12	Financial Projections Summary Based on FPC Capacity Additions
II-13	Capacity Factors by Fuel Type and Ownership Category, For Representative Years
II-14	Estimates of Capital Costs for Nuclear Units, 1970-1990
II-15	Fossil Unit Capital Expenditure Cost Assumptions, 1970-1990

Preceding page blank

Exhibit

II-16 Estimates of Capital Costs for Fossil-Fueled and Hydraulic Units, 1970-1990
II-17 Implications of Industry Projections of Capital Costs In Terms of Escalation Rates, 1972-1990
II-18 Pattern of Cash Flows for Capital Projects; Annual Expenditure of Funds
II-19 Forecasts of Electric Demand Growth
II-20 *Electrical World* Projections: Total Sales, System Output, Peak Load, Capability, and Margin
II-21 Coal and Oil Conversions, 1975-1980
II-22 Fuel Cost Assumptions, 1974-1990
II-23 Financial Assumptions: Capital Costs, Capital Mix, Tax Rates
II-24 GNP Deflator; For Use in Constant Dollar Analysis
II-25 Income Statement for Investor-Owned Electric Utilities
II-26 Balance Sheet for Investor-Owned Electric Utilities
II-27 Applications and Sources of Funds for Investor-Owned Electric Utilities
II-A-1 Interactions between the Environment and the Physical and Financial Characteristics of the Electric Utility Industry
II-A-2 Determinants of Plant and Equipment in Service and in Construction for the Electric Utility Industry
II-A-3 Determinants of Uses of Funds for the Electric Utility Industry
II-A-4 Determinants and Composition of Total Sources of Funds for the Electric Utility Industry
II-A-5 Determinants of Revenues, Expenses, and Profits for the Electric Utility Industry

CHAPTER I

INTRODUCTION AND SUMMARY OF BASELINE CASE FINANCIAL PROJECTIONS FOR THE ELECTRIC UTILITY INDUSTRY

This volume of the report presents financing projections for the electric utility industry before taking into account the impact of federal pollution control requirements. These projections constitute a "baseline" against which pollution control cost estimates will be evaluated.

TBS has devoted substantial effort to developing and validating the baseline projections because they are key to the impact analysis; both the projections themselves and the method for representing the industry's operations and accounting are used in the impact analysis pahse. The general approach used in the overall study has been first to project conditions in the industry in the absence of pollution control regulations (the baseline case), then to project conditions with the regulations and, finally, to measure the impacts by contrasting one set of conditions with the other. The following section describes in more detail the key elements of the baseline projections.

APPROACH

The approach which TBS has followed to develop and present the baseline projections has three major elements: First, TBS selected five financial indicators as summary statistics descriptive of the detailed financial projections developed for the purposes of this report. The summary statistics are:

- Capital Expenditures
- External Financing
- Operating Revenues
- Operating & Maintenance Costs
- Average Consumer Charges

These indicators are used in the later volumes to compare the baseline conditions with those resulting from the use of alternative sets of operating projections. The indicators are more fully explained at the end of this chapter in the context of specific financial baseline projections.

A second element of TBS' approach was to rely upon public data sources. TBS used, to the maximum extent possible, actual operating data through 1975 and projected and announced operating characteristics developed by industry sources and by other research organizations which specialize in such forecaseing activities. The focus of the TBS effort has been on the determination of the financial implications of various conditions and courses of action and not upon developing a unique set of operating projections. Therefore, the approach had depended upon gathering and integrating existing projections on demand for electricity, capacity additions, fuel costs, capacity factors, and so on. The existing projections are then reconciled with other sources of data such as:

- Historical data
- Emerging trends discussed in relevant literature
- Specific new data such as announced cancellations, new construction costs or fuel prices.

A critical dimension of the reconciliation process has been to achieve a degree of consensus from practitioners and policy-makers on the validity of the operating projections which TBS has adopted. The areas in which significant discussion has occurred and for which the most uncertainty exists include:

- Demand: the rate at which sales and peak load will grow over the next fifteen years. Events described in Volume I, such as the energy crisis, general economic conditions, and environmental concerns have upset traditional growth patterns and rate structures;
- New capacity or construction: the amount of new capacity which the industry should build (or postpone) to meet the projected level of sales. Because of the uncertainties in future sales growth patterns, it has become difficult to plan the rate at which such additions will be required;
- New plant costs and fuel prices: These major capital and operating costs continue to be subject to the vagaries of inflation and market forces. While many estimates have been supplied in this area, a high degree of uncertainty remains, particularly in the projection of costs for coal, oil and uranium and therefore in the projections of future plant type as well;
- Financial and accounting structure: Finally, though perhaps less important, there are uncertainties related to the financial costs and accounting conventions affecting the industry.

Each of these areas is discussed more fully in Chapters 3 through 5.

The third element of TBS' approach is the use of TBS' Policy-Testing model of the electric utility industry, PTm (Electric Utilities) to trace through the detailed accounting and financial implications of the projected operating conditions described above. PTm, which is at the heart of the TBS approach, is described in some detail in Appendix A, with special attention to the financial module.

The final portion of this chapter presents the summary financial statistics for the baseline projections and a brief description of the key operating projections from which the baseline financial projections were derived.

In the presentation, two conventions have been followed and are worth mentioning at the outset. First, while PTm performs calculations in current dollars so as to accurately reflect the impact of price inflation on depreciation tax shields, etc., most of the text discusses the projections in terms of constant 1975 dollars so as to aid the reader's understanding of the magnitude of the number in relation to the industry's current financial statistics. Second, while the calculations are done on a yearly basis for the 1975-1990 period, for simplicity the text generally focuses on aggregate numbers for the overlapping periods 1975-1980 and 1975-1985.

SUMMARY OF BASELINE CASE FINANCIAL PROJECTIONS

The financial projections are based upon the conditions which TBS determined best describe the future of the electric utility industry. They are, of course, subject to the uncertainties described above. While each area is discussed in subsequent chapters, sales growth rates and levels of capacity additions are briefly included here, because they are critical assumptions to the baseline projections. TBS has used an annual growth rate in sales of 6.1 percent for the 1975-1980 period and 5.3 percent annually from 1981 through 1990. Both rates are well below the growth rates of the decade prior to 1974. They reflect those forecasts made after the energy crisis and are discussed in Chapter 2. The capacity additions projected for the next ten years reflect the industry's inability to respond rapidly to a decline in growth rates. Thus, despite cancellations and postponements of new capacity, the industry's generating capacity is projected to grow more rapidly than demand through 1980. For the 1981-1990 period, capacity additions are assumed to be sufficient to maintain a capacity reserve margin of at least 20 percent, a generally-accepted objective in the industry.

The table and discussion below summarize the financial projections. Exhibit II-8 provides financial data for specific years in greater detail.

SUMMARY OF BASELINE FINANCIAL PROJECTIONS
(1975 dollars)

	1975-1980	1975-1985
Capital Expenditures (billions)		
- Net of Change in Construction Work in Progress	118.3	237.1
External Financing (billions)	89.8	191.2
Operating & Maintenance Costs	267.3	510.3
Operating Revenues	469.0	903.9
Average Consumer Charge (mills/kwh at end of period)	31.7	32.0

Source: Exhibits II-6 and II-8, PTm (Electric Utilities) Projections and Assumptions

Capital Expenditures are defined as the cumulative cash expenditures for the plant and equipment which is placed in service during any given year. The expenditures reported are thus net of any change in construction work in progress (CWIP). Further, this definition refers only to cash outlays actively required by the utilities and does not include allowance for funds during construction (AFDC). As an example, the baseline projections for the next decade[1] (1975-1985) indicate that capital expenditures net of changes in CWIP will total $237.1 billion in constant 1975 dollars. In addition, CWIP will increase from $28.5 billion at the end of 1974 to $63.0 billion at the end of 1985, an increase of $34.6 billion. Thus, total expenditures for plant and equipment during the next decade will be $271.7 billion--the sum of $237.1 billion in the form of capital expenditures for equipment placed in service and $34.6 billion in terms of additions to the CWIP account. These latter expenditures are then allocated to the time period in which that equipment is placed into service.

External Financing requirements are the sum of long-term debt, preferred stock and common stock issues in any given year, including the refinancing of maturing long-term debt. These capital market requirements during the next decade are expected to total $191.2 billion in constant 1975 dollars--approximately 80.6 percent of capital expenditures during the same period. The remaining funds required to finance the industry's expenditures for additions to plant in service and to CWIP will be generated internally in the form of retained earnings, depreciation and tax deferrals.

---

[1] *Actually, the 1975-1985 period encompasses 11 years; however, reference within this report will be made as if this time period were a "decade."*

Operating and Maintenance Costs consist of all the direct costs of operation of the electric utilities. Fuel represents the largest single component of these costs. Historically (prior to 1974), fuel accounted for slightly under half of total operation and maintenance expenses. One result of the rapid escalation in fuel prices during 1974 has been to increase that share to approximately 60 percent. The TBS baseline projection is that total operating and maintenance expenses will amount to $267.3 billion in the 1975-1980 period and $510.3 billion through 1985.

Operating Revenues represent the total amount of money paid by utility customers for electricity in a given period. To put it another way, operating revenues are the amount required by the utilities to cover operating, capital, and other costs. As such, it represents the best basis for measuring the potential impact on consumers of pollution control regulations which require capital investments as well as direct operating costs. The baseline projections for total utility operating revenues are $469.0 billion in the 1975-1980 period, and $903.9 billion through 1985 (1975 dollars). These figures indicate an average annual revenue rate of approximately $82 billion, up from about $50 billion in 1974 (notated in 1975 dollars).

Average Consumer Charges are obtained by dividing operating revenues by total sales to ultimate customers. Thus, they represent the average cost of electrical energy per kilowatt-hour. This average charge is expected to increase slightly in real terms from 29.6 mills per kilowatt-hour in 1975 to 32.0 mills per kilowatt-hour in 1985. In current dollar terms, consumer charges per kilowatt-hour are expected to increase from 29.6 mills in 1975 to 53.5 mills in 1985--

an increase of about 6.1 percent per year which is primarily due to inflation.

COMPARISON WITH ALTERNATIVE SCENARIOS

It is against this base of financial results that the cost of pollution control will be measured. However, before proceeding in the discussion of the components (demand, capacity, costs and other financial parameters) which underlie these results, it is well to consider briefly the financial results based on three alternative projections of sales growth or additions to capacity. They are included, in part, to illustrate how sensitive the financial indicators are to changes in the operating projections.

Financial Summary: Based Upon December 1974 Baseline Projections

The baseline projections above differ somewhat from the baseline projections made by TBS and published by EPA, in December 1974, in Economic Analysis of Effluent Guidelines--Steam Electric Power Plants. There are two key reasons. First, the current baseline is driven by an updated forecast of load growth which assumes that the electric utility industry will not return to its historic rate of growth, but will grow more slowly in the future. Second, capital and operating cost factors have been revised upward primarily to reflect continued high rates of cost escalation in the construction industry and to reflect the quantum increase in fossil fuel prices which occurred during 1974. The December 1974 projections will often be referred to as "previous" baseline projections.

The following summary illustrates the major financial indicators[2] as they appeared prior to accounting for these two factors.

FINANCIAL SUMMARY: PREVIOUS BASELINE CONDITIONS
(1975 dollars)

	1975-1980	1975-1985
Capital Expenditures (billions)--Net of change in CWIP	$107.3	$247.5
External Financing (billions)	78.0	177.7
Average Consumer Charge (mills/kwh at end of period)	29.5	28.2

Source: TBS, Economic Analysis of Effluent Guidelines--Steam Electric Power Plants, December 1974

The specific changes which affected capital expenditures are presented below for the short and long term:

CHANGE IN BASELINE CAPITAL EXPENDITURES
(billions of 1975 dollars)

	1975-1980	1975-1985
PREVIOUS BASELINE	$107.3	$247.5
+ Change due to Load Growth	(8.8)	(64.7)
+ Change due to Cost Escalation	19.8	54.3
= CURRENT BASELINE	118.3	237.1

---

[2] *It should be noted that all constant dollar estimates from the EPA report in December 1974 have been adjusted in the current analysis to a 1975 base.*

Exhibits II-9 and II-10 provide selected data which summarize (1) the previous baseline; and (2) the combination of the growth projections contained in the previous baseline with the revised cost factors. The table above highlights the differences in capital expenditures detailed in Exhibits II-8 through II-10.

Financial Summary Based Upon Historic Load Growth

While these data provide a comparison of the TBS baseline with the baseline utilized in previous EPA analyses, other comparisons can be made to evaluate, for example, the effect of returning to historic growth levels. Exhibit II-11 provides selected summary data for this condition.

The financial implications of returning in 1976 to the historic growth pattern of 7.2 percent annually and continuing at that level through 1990 are as follows:

FINANCIAL SUMMARY: HISTORIC GROWTH RATES
(1975 dollars)

	1975-1980	1975-1985
Capital Expenditures (billions)	$119.5	$333.1
External Financing (billions)	116.2	312.44
Average Consumer Charges (mills/kwh at end of period)	31.2	33.4

Source: Exhibit II-11, PTm (Electric Utilities)

Capital expenditures in the short run would not be significantly impacted since the stream of capacity additions scheduled during the 1975-1980 period is the same. However, the capacity additions required to maintain an adequate reserve margin (e.g., 20 percent) during the early 1980s would increase from 149.2 to 275.7 million kilowatts. These capacity expansion plans would require an additional $94.2 billion in capital expenditures and $121.2 billion in external financing during the next decade. In addition, internally generated funds would drop from 20 percent of capital requirements to less than 10 percent. The net effect of historic growth on the consumer would be an increase in 1985 consumer charges of approximately 4 percent.

Financial Summary Based upon Federal Power Commission Capacity Additions with TBS Growth Projections

If the TBS baseline projections regarding sales and peak demand growth are used, but the capacity additions schedule announced by the Federal Power Commission is adhered to, then the financial profile is as follows:

FINANCIAL SUMMARY: FPC ADDITIONS AND TBS GROWTH RATE
(1975 dollars)

	1975-1980	1975-1985
Capital Expenditures (billions)	$130.5	$239.7
External Financing (billions)	94.4	190.7
Average Consumer Charge (mills/kwh at end of period)	32.1	31.9

Source: Exhibit II-12, PTm (Electric Utilities)

Over the long run, the construction of generating capacity as currently planned differs little from the baseline conditions. The FPC announced additions would result in 10.4 percent more capacity placed in operation from 1975-1980 than the baseline projection, but 12.3 percent less in the 1981-1985 period. The total additions over the entire period would be the same as in the baseline case.

Since more capacity is placed into service in the late 1970s, capital expenditures and external financing requirements during this period would increase by about 10 percent and consumer charges would increase by about 2 percent. However, these additions would temper the capacity requirements in the early 1980s, resulting in a net increase of only $1.8 billion dollars in capital expenditures and a marginal decline in external financing requirements during the next decade.[3] Consumer charges would not differ from the baseline case by 1985. Exhibit II-12 provides selected data for specific years under this scenario.

The following chapters present the data and assumptions upon which the baseline projections are based. Various elements of the baseline projections are listed in Exhibits II-1 to II-8 for reference.

---

[3] *The decline in external financing requirements follows from the earlier inclusion of capital expenditures into the rate base.*

CHAPTER 2
BASELINE DEMAND PROJECTIONS

A basic component of projections for the electric utility industry is demand. "Demand" is a term often used loosely to refer either to peak demand or to energy consumed over a period of time. In this report, energy consumed over a year's time will be referred to as "sales." The rate of energy consumption at any point in time will be referred to as "demand" or "load." The highest rate of consumption during a year will be referred to as "peak demand" or "peak load." Peak load growth determines the industry's total capacity needs. The ratio of energy sales to peak demand influences the mix of types of capacity, that is, baseload or peaking capacity, built to meet total peak demand. The following discussion covers sales and peak load growth both as they actually occurred between 1960 and 1975 and as they are projected for 1976 through 1990.

It should be noted that demand analysis is becoming more precise and detailed because of the current interest on the part of regulatory commissions and other government bodies in rate structure modifications. Rate structure changes may affect future demand patterns and, therefore, may also affect the other determinants of the industry's financial profile: capacity, costs, and financial structure. However, because the magnitude of the impact of such rate structure changes is at present unclear, the demand projections used for this analysis do not presume such changes.

The pattern of demand as it has existed in the past and as it is projected for this report is summarized in the following table.

SUMMARY OF BASELINE DEMAND PROJECTIONS

	1960	1965	1970	1975	1980	1985	1990
Sales to Ultimate Customers (billions of kilowatt-hours)	683.2	953.4	1,391.4	1,736.5	2,334.7	3,022.5	3,913.0
5-year Growth Rate	-	6.9%	7.9%	4.5%	6.1%	5.3%	5.3%
Non-Coincident Peak Demand (millions of kilowatts)	133.0	186.9	275.4	358.1	478.0	613.3	794.0
5-year Growth Rate	-	7.0%	8.1%	5.4%	5.9%	5.2%	5.3%

Source: Exhibits II-1, II-2, II-3, PTm (Electric Utilities)

The data shown for the period 1960-1975 represent actual industry experience. During most of that period (1960-1973), the electric utility industry sustained a relatively constant rate of growth, equal to 7.3 percent in terms of sales to ultimate customers and 7.6 percent in terms of peak load demand. In 1974, however, sales to ultimate customers actually declined by 0.1 percent, while peak demand increased by only 1.6 percent. These substantial declines in growth rates were primarily the result of both price and non-price induced energy conservation following the Arab oil embargo. Many observers felt that by 1975 peak demand growth rates would return to historical levels, and perhaps even make up for the 1974 decline.

Neither of these expectations seems to have materialized. The data for 1975 indicate that sales to ultimate customers and peak demand increased by approximately 2 percent over 1974 levels, a rate that falls far short of a return to earlier patterns. Sales growth in the first twelve weeks of 1976 has been 5.9 percent above the year-earlier level, but is inconclusive evidence of any long-term trend.

The baseline projections for demand in the 1976 through 1980 period are based on growth rates somewhat below the historical experience. Specifically, the baseline projections assume growth in sales to ultimate customers of 6.1 percent for 1976-1980, 5.3 percent for 1981-1985, and 5.3 percent for 1986-1990. The rates of growth in peak demand are 5.9 percent, 5.2 percent, and 5.3 percent, respectively. The TBS projections are based primarily on forecasts made by others, modified where appropriate to reflect the industry's actual experience in 1974 and 1975. A brief comparison of these and various other projections is presented below.

A first comparison can be made between the TBS baseline projections and the projections published in an earlier study by TBS for EPA, Economic Analysis of Effluent Guidelines--Steam Electric Power Plants, December 1974. The following table summarizes the differences in growth assumptions used in the two projections.

CHANGE IN DEMAND ASSUMPTIONS

	TBS Demand Projections		TBS December 1974 Demand Projections	
	Sales to Ultimate Customers	Non-Coincident Peak Demands	Sales to Ultimate Customers	Non-Coincident Peak Demands
1974	-0.1%*	1.0%*	-3.4%	1.0%
1975	2.1*	2.1*	2.7	4.6
1976-1980	6.1	5.9	7.1	6.5
1981-1985	5.3	5.2	6.6	6.0
1986-1990	5.3	5.3	5.5	5.5

---

*actual; from Edison Electric Institute

This comparison in demand projections relates to the comparison of financial projections presented in Chapter 1, page 5.

The TBS projections can also be compared to projections made by other analysts of the electric utility industry and by representatives of the industry itself. These projections fall into two classes:

(1) Forecasts made prior to the Arab oil embargo of 1973; and

(2) Forecasts developed since the oil embargo, especially those made since the industry's 1974-1975 reduction in sales growth.

The sales growth rates projected for 1975-1985 for representative sources in these two categories are presented in the following tables.

(1) **DEMAND FORECASTS DEVELOPED USING PRE-EMBARGO INDUSTRY DATA**

		Annual Sales Growth Rates	
Source	Pub.Date	1975-1980	1975-1985
Electrical World	(9/73)	7.0%	6.5%
National Electric Reliability Council	(4/74)	7.5%	7.1%
National Power Survey (TAC-Finance) "historic growth case"	(12/74)	7.1%	7.1%
National Power Survey (Forecast Review Task Force)	(8/75)	9.1%	7.0%
Projected Independence (FEA - $7 oil)	(11/74)	6.6%*	6.9%

(2) **DEMAND FORECASTS DEVELOPED USING POST-EMBARGO ASSUMPTIONS**

		Annual Sales Growth Rates	
Source	Pub.Date	1975-1980	1975-1985
Electrical World	(9/74)	6.1%	5.3%
Electrical World	(9/75)	6.7%	6.2%
National Power Survey (TAC-Finance) "moderate growth case"	(12/74)	7.1%	6.6%
Project Independence (FEA - $11 oil)	(11/74)	5.5%*	5.7%

**Based on 1972-1980 figures*

A return to the historic rate of growth of approximately 7.5 percent per year 1976-1980, such as is characteristic of the pre-embargo forecasts, would result in sales to ultimate customers in 1980 of 2,493 billion kilowatt-hours, a level 6.3 percent above the TBS baseline forecast for 1980. The projections in the second table are more in keeping with those which TBS has adopted. Exhibits II-19 and II-20 provide additional detail on comparative forecasts in selected years.

CHAPTER 3

BASELINE CAPACITY AND GENERATION PROJECTIONS

The second major set of operating projections for the electric utility industry concerns the industry's capacity and its annual output (generation). Capacity is the amount of electric power (measured in kilowatts) which existing plants are capable of producing at a given moment. Generation is the amount of electric energy (measured in kilowatts per hour) actually produced by the existing capacity over some period of time.

The projections of capacity levels for future years result from estimates of several individual elements: capacity additions by fuel type; conversions of existing gas and oil generating capacity to coal and oil; capacity retirements; and reserve margins. The use of capacity projections in calculating generation by fuel type depends upon estimates of utilization rates or capacity factors for plants in each fuel category.

The TBS projection of total capacity and generation and the related individual elements are based on the examination and, as necessary, the modification of existing projections developed by other organizations and industry specialists. This chapter presents the projections and describes the function of each element.

CAPACITY

Installed Capacity in 1974

The profile of capacity by fuel type as it existed in 1974 (the base year for the projections) serves as a point of reference for highlighting the changes which are projected for the future. In 1974, generation capacity totaled 476 million kilowatts, 71.3 percent of which was accounted for by fossil-fueled units. Hydroelectric capacity was second in importance with 11.6 percent of the total, while nuclear and peaking capacity represented 6.6 and 8.7 percent, respectively.

The 1974 level for hydroelectric power represented a decline in share from previous years, but nuclear and peaking units significantly increased in their share of capacity by 1974. The table below summarizes the installed capacity by fuel type as it existed in 1974.

1974 UNITED STATES
INSTALLED GENERATION CAPACITY

Generator Type		Installed Capacity (million kw) 1974		Percentage of Total Capacity 1974
Fossil		339.4		71.3
Coal	185.8		54.7	
Oil	66.3		19.5	
Gas	87.4		25.7	
Nuclear		31.6		6.6
Hydroelectric		55.4		11.6
Pumped Storage		8.3		1.7
Peaking Units		41.3		8.7
		476.0		99.9%

Source: EEI, FPC publications; coal, oil and gas capacity percentages resulted from a computerized analysis of Table I, pp. 3-44 NCA Steam Electric Plant Factors, 1973

Total Capacity Projections (1975-1990)

The trends which were becoming apparent in 1974 continue to be reflected in the baseline capacity projections for the period of analysis. The table below summarizes the projections by prime mover.

NATIONAL BASELINE SUMMARY
CAPACITY MIX BY PRIME MOVER SELECTED YEARS
(millions of kilowatts)

PRIME MOVER	1975	1980	1985	1990
Coal	196.2	276.8	332.9	434.6
Oil	72.3	96.1	91.2	85.5
Gas	89.2	48.2	41.0	33.0
Nuclear	40.7	79.7	132.0	219.8
Hydro	57.6	66.4	73.5	85.7
Pumped	8.5	11.8	16.3	23.8
Peaker	44.8	52.0	64.1	85.6
TOTAL	509.4	631.0	751.0	968.0

Source: Exhibit II-3, PTm (Electric Utilities)

Total capacity is estimated to double between 1974 and 1990. However, the most prominant development in the projection period is the shift in share by fuel types. Oil-fired units will increase slightly as a percent of total capacity through 1978, then drop to about 15.2 percent in 1980 as a result of conversions to coal and a slowed rate of oil-fired additions. By 1990, there will be negligible additions utilizing oil, causing the share of capacity accounted for by such units to fall to slightly under 9 percent. Nuclear power plants, on the other hand, will probably continue to grow in their share of the total, even though some plants expected to be in service by 1975 and the late 1970s have already been cancelled or postponed. Natural gas is projected to undergo a significant drop in share of total capacity, from almost 18.4 percent in 1974 to 3.4 percent by 1990. As with oil, this drop is the result of both conversions to other fossil fuels and a slowed rate of new additions. All of these shifts in relative share of total capacity are integrally tied to the characteristics of additions to capacity.

Capacity Additions

The projections of capacity beyond 1974 are driven primarily by the type, timing and amount of additions which the industry has scheduled for future years. Those plants have been radically modified as a result of the changes in prices and sales growth precipitated by the oil embargo and other factors. As a result, many postponements and cancellations of new units occurred in 1974 and 1975. Nevertheless, it appears that the industry has been optimistic about the need for further postponements and cancellations. This optimistic posture has occurred based on the assumption that growth rates would recover sharply during 1975 and is reflected in the Federal Power Commission's published announcements of additions (April 1975). If the reported level of capacity additions was combined with the TBS baseline projections for sales, the resulting capacity would far exceed the level of demand and an adequate reserve margin by 1980. Even if growth rates were to return to historic levels during the 1976-1980 period, the FPC reported additions would still result in reserve margins in excess of the industry standard.[1] Furthermore, the announced additions do not seem to fully reflect the impact of natural gas curtailments and/or Federal Energy Administration actions to restrict generation from oil and gas. Therefore, in developing the baseline capacity projections for the 1976-1980 period TBS has modified the FPC additions to compensate for the above-mentioned uncertainties in the following manner:

---

[1] *Reserve margins are discussed on page II-27. In the examples which project on the basis of FPC additions, the first would represent a reserve margin of over 30 percent, the second would yield a 24 percent reserve margin.*

BASELINE CHANGES FROM FPC ADDITIONS
(millions of kilowatts)

	Baseline Additions	FPC Additions	Percent Decrease
1976	26.1	26.6	2%
1977	26.9	28.3	5
1978	28.7	31.9	10
1979	27.4	32.2	15
1980	32.3	40.4	20

While the table above illustrates total percentage decreases from FPC additions, these decreases are not evenly distributed among fuel types. A further illustration in the table below specifies by year and fuel type the percentage of FPC additions which TBS has eliminated in its projection of capacity additions.

STEAM ELECTRIC POSTPONEMENTS
AND/OR CANCELLATIONS AS % OF FPC ANNOUNCED
ADDITIONS

Year In-Service	Coal	Oil	Gas	Nuclear
1976	0%	0%	33%	0%
1977	0	15	67	10
1978	0	50	100	20
1979	0	60	100	20
1980	0	70	100	20

All hydroelectric and pumped storage projects were assumed to be completed on schedule. Additional peaking units were scheduled to begin operation in 1977 through 1980 where required to meet the above-mentioned baseline capacity additions schedule.

Nuclear and coal generation capacity are expected to account for almost 88 percent of the additions by 1980, and 82 percent between 1985 and 1990. While the nuclear share of total additions will increase to 38.7 percent in 1980, coal additions will represent almost half of the new additions. Three years ago observers expected nuclear power to reach a 50 percent share by 1980.

There are a number of factors which have caused revisions in the type of capacity which is expected to dominate additions. The pressure to find alternatives to oil and gas continues: coal and nuclear power are currently the only potential candidates for use on a large scale, although each has constraints to its further growth. The use of coal will be hampered by the amounts of Western low-sulfur coal that will actually be mined and shipped. Strip mining legislation, other environmental restrictions and limited rail capacity may slow the production of Western coal. On the other hand, increasing concerns over various safety issues associated with nuclear generation continue to affect the utilization of existing plants and delay the planning and construction of new nuclear units. In addition, complications which have arisen concerning the supply and cost of uranium have caused further delays and postponements. Given the long lead times required for planning, licensing, siting, designing, and constructing nuclear plants, each delay casts further doubt on the expansion of nuclear-based generating capacity. Finally, analyses of cost factors had previously attributed an operating cost advantage to nuclear power and a capital cost advantage of coal generation. However, escalating capital costs for both types of units along with higher nuclear operating costs have made it difficult to cite cost advantages in support of one form of energy over the other for purposes of projecting additions during the next 15 years.

The net result of these factors seems to be a swing to coal as the dominant source of new generating capacity. Nuclear units will be constructed at a significant rate--over one-third of all additions--but at rates below earlier estimates. Present projections place total nuclear capacity at 79.7 million kilowatts by 1980 and 132.0 million by 1985. Coal capacity will total 276.8 million kilowatts in 1980 and 332.9 million by 1985.

The overall trend for fossil additions will peak by 1979 with additions of 19.2 and 16.7 million kilowatts in 1979 and 1980, respectively, when early postponements go into service. Then, during the 1980s, total fossil additions will decline slightly as oil and gas additions cease entirely. This trend is being hastened by the Federal Energy Administration's desire to minimize reliance on oil and gas and the potential deregulations of natural gas which would make it uneconomic as a boiler fuel. As a result, natural gas capacity additions are expected to be negligible by 1977; oil additions will also be negligible by 1981.

Peaker, hydroelectric, and pumped storage additions are expected to maintain a steady share of total capacity additions.

NATIONAL BASELINE SUMMARY
CAPACITY ADDITONS BY PRIME MOVER
SELECTED YEARS

(millions of kilowatts)

PRIME MOVER	1975-1980	1975-1985
Coal	79.0	149.2
Oil	17.6	17.6
Gas	4.4	4.4
Nuclear	48.0	100.3
Hydro	11.4	18.8
Pumped	3.5	8.0
Peaker	13.6	28.6
TOTAL	177.5	326.9

Source: Exhibit II-2, PTm (Electric Utilities)

Gas and Oil Conversions

Another dimension of capacity projections is the conversion of some gas units to coal or oil and some oil units to coal. These conversions stem from the rising costs of gas and oil, the curtailment of gas supplies, and federal conversion orders from FEA. Statistics for the conversions from 1974-1980 have been projected from EPA and FPC estimates and compiled in a study by Foster Associates. The estimated capacity which will be converted in the absence of the Clean Air Act during the 1975-1980 period is listed below.

GAS AND OIL CAPACITY CONVERSIONS
SINCE 1975
(million kilowatts, cumulative)

	Gas to Coal	Gas to Oil	Oil to Coal
1975	0.1	0.5	0.4
1976	1.8	5.3	1.1
1977	3.7	10.5	3.4
1978	5.5	15.8	4.9
1979	7.9	21.0	6.4
1980	9.2	26.3	11.1

Source: Foster Associates, Impact of Natural Gas Curtailments on Electric Utility Plants (August 1975), Exhibit II-21

These conversions are included in the capacity projections as additions to the coal and oil components.

Capacity Retirements

Some portion of existing capacity is scheduled to be removed from service each year.[2] However, increasing reserve margins, higher capital costs, declining revenues, along with increased cancellations and postponements, may have a noticeable impact on capacity retirements through 1980. The combination of these factors may create a financial environment in which utilities find it more attractive to extend the life of existing capacity than to construct and finance new facilities. On the other hand, these same factors may create an environment in which the utilities attempt to decrease excessive operating and maintenance expenses and fuel costs by accelerating the retirement of older units. Such retirements occur when capacity additions which were scheduled and begun before demand growth slackened are too close to completion to be cancelled or rescheduled.

In light of this uncertain situation, TBS has examined several rates of capacity retirements and has selected those suggested by National Power Survey TAC-Finance Committee for fossil fuels, and by EEI for hydro and peaking generation. The retirement projections for selected years are displayed in the following table.

---

[2] *It should be noted that units which undergo drastically reduced loads (i.e., are not actually retired) are still included in the overall capacity projections.*

PLANT RETIREMENTS
CUMULATIVE - FROM 1975
(millions of kilowatts)

	1975	1980	1985	1990
Total	2.4	22.0	51.2	84.2

Source: Exhibit II-3, PTm (Electric Utilities)

The retirements for the individual fuel types are outlined in the following chart.

RETIREMENT RATES

Type of Capacity	Percent Retired Annually 1972-1990	
Fossil	0.4%	1972-73
	0.5%	1974
	0.6%	1975
	0.7%	1976-80
	1.2%	1981-90
Nuclear	No retirements through 1990	
Conventional Hydro	0.1%	1972-90
Peaking Units	1.0%	1972-90
Pumped Storage	No retirements through 1990	

Source: 1972-95, EEO; 1976-90, National Power Survey

Reserve Margins

Reserve margins are the amount of generating capacity which the industry has available in excess of the level required by annual non-coincident peak demand. The amount of capacity which must be added is determined by the projected level of peak demand plus a reserve margin of at least 20 percent.[3]

Some observers within the industry have warned that excessive postponements and/or cancellations could result in capacity shortages by 1980. In fact, however, if peak demand growth returned to historic levels, the baseline capacity additions described in this chapter would still be more than adequate to avoid a serious shortage of generation capacity; under those conditions the reserve margin in 1980 would be nearly 22 percent.

If, on the other hand, the future growth rates and capacity additions do parallel those projected by TBS, reserve margins will decline gradually from the 1975 level of 37.6 percent to 29.4 percent by 1980. This level is still significantly above the 20 percent margin. In order to realize a reserve margin closer to 20 percent in the 1981-1990 period, TBS has assumed that the capacity added during the 1980s will be at the level needed in order to reach a 20 percent reserve margin by 1985 and maintain that level through 1990.

The reserve margins which are implied by the TBS projections of peak demand and capacity are listed below:

---

[3] *A reserve margin of 20 percent is the industry standard of adequate capacity.*

RESERVE MARGINS
(1970-1990)

	Peak Demand (million kwh)	Reserve Margins (%)*
	-----------Historical-----------	
1970	275.4	19.0
1971	293.1	21.0
1972	320.2	19.6
1973	345.2	21.6
1974	350.7	30.6
	-----------Projected-----------	
1975	358.1	37.6
1976	381.3	36.4
1977	403.8	34.0
1978	426.9	32.3
1979	450.8	30.8
1980	476.0	29.4
1985	613.3	20.0
1990	794.0	20.0

Source: Historical figures: EEI
Projected figures: TBS based on capacity and demand projected described previously.

The abrupt increase in reserve margins from 21.6 in 1973 to 30.6 in 1974 was due to the decrease in the peak demand growth rate and the inability of individual utilities to halt capacity additions already under construction. This inability meant that, in the short run, excess generation capacity was built without the proportional increase in peak demand which would have kept reserve margins closer to the 20 percent level.

CAPACITY FACTORS AND GENERATION

Capacity Factors

In order to determine operating and maintenance costs for projected capacity levels, it is necessary to estimate the rate of equipment utilization by type of fuel used. Consequently, the number of kilowatt hours actually generated (sales plus generation not sold) by units driven by each type of fuel must be estimated by assuming capacity factors in order to provide a basis for calculating operating costs.[4] Two sets of conditions determine capacity factors. First, all units are subject to both routine maintenance shutdowns and forced outages which reduce availability. Second, as demand varies, units with high proportions of variable to fixed costs (such as peakers) are used as little as possible, whereas units with high fixed and low variable costs (such as nuclear units) are operated continuously whenever possible. These conditions have both been considered by TBS in developing the estimates of capacity factors by fuel type which are presented in Exhibit II-13.

Capacity factors for nuclear units are based on optimal usage equal to total availability. The actual experience with nuclear units to date has been considerably below the optimal level because of an initial period of about three years during which the units reach a plateau of generation, a "power ascendancy curve." In addition, other operational difficulties have contributed to a low rate of utilization, though this is projected to improve. For coal units an optimal utilization rate equal to availability is also used. For oil, gas, internal combustion and peaking units, the optimal rate is less than availability primarily because of high fuel costs.

---

[4] *The capacity factor represents the average percentage of time the unit is in operation during the year. The capacity factor is calculated by dividing the generation (kwh) by the product of capacity available (kw) and 8760 hours.*

Generation Projections

The amount of electricity which will be generated from the capacity levels projected--after the capacity additions, conversions, retirements and capacity factors have been integrated--will be approximately 2,565.6 billion kilowatt-hours by 1980. By that year coal will account for 49.2 percent of the fuel mix breakdown. In 1985, nuclear generation will have captured some of the fossil share, and will account for about 22 percent of the total generation. Coal will maintain its 50 percent share through 1990, with the nuclear share reaching about 28 percent in that year. The following table displays generation of electricity by the fuels used for selected years. In addition, Exhibit II-4 provides the annual generation by fuel type.

NATIONAL BASELINE SUMMARY
GENERATION MIX BY PRIME MOVER
(billions kwh)

	1975	1980	1985	1990
Coal	857.2	1261.4	1644.9	2135.6
Oil	275.5	361.3	334.4	276.8
Gas	262.5	142.4	122.4	90.1
Nuclear	192.3	404.1	726.7	1201.1
Hydro	250.0	301.8	359.1	410.0
Pumped	34.1	49.4	73.4	105.8
Peaker	36.6	45.1	60.5	80.5
TOTAL	1908.2	2565.6	3321.4	4300.0

Source: Exhibit II-4, PTm (Electric Utilities)

Fossil Fuel Requirements

These projections of generation mix have an associated distribution of fuel requirements. The fuel requirements are derived from two types of information: the heat rates of the units and the Btu content of the fuels. Since the heat rate varies for old and new units and is complicated by other factors, the assumptions used to calculate heat rates, fuel prices and quantities are described more fully in Chapter 4, page II-5. The Btu content for oil and gas has been assumed to maintain the 1973 levels of 145,225 Btu per gallon and 1,024 Btu per cubic foot, respectively. Coal is projected by Sobotka & Co., Inc. to decline from 11,125 Btu/lb. to 10,875 Btu/lb by 1980 and 10,600 by 1985 as a result of increased use of Western low-Btu low-sulfur coal. TBS has estimated the share of low-sulfur coal to be about 30 percent by 1985. Given these assumptions, the quantities of fossil fuels which will be burned at the generation levels projected above are summarized in the following table.

FOSSIL FUELS CONSUMED FOR GENERATION OF ELECTRICITY SELECTED YEARS

	1975	1980	1985	1990
Coal (mm tons)	387.8	610.8	807.0	1,022.9
Oil (mm bbls)	533.5	624.5	599.8	534.2
Gas (bcf)	2,984.0	1,690.3	1,534.8	1,262.3
Total Generation (billion kwh)	1,908.2	2,565.6	3,321.4	4,300.0

Source: Exhibit II-5, PTm (Electric Utilities)

CHAPTER 4
COST FACTORS

Chapter 4 reviews the TBS estimates of capital costs and the fuel and non-fuel segments of operating and maintenance expenses.

CAPITAL COST FACTORS

Unit construction costs for the electric utility industry have increased significantly in the last few years and are projected to continue to escalate through the early 1980s. As an example, the cost of a new coal plant has risen from an average of $150 per kilowatt (current dollars) for a plant put into service in 1972 to an estimated cost of almost $500 for one coming in service in 1980 and of almost $700 in 1985. These costs exclude pollution control and AFDC. The cost of a nuclear plant over the same period has risen from $245 per kilowatt for a plant in service in 1972 to almost $700 in 1980 and $900 in 1985. The causes of recent and projected construction cost increases include inflation in the cost of labor and materials, increases in the complexity of generating units, licensing delays, slippage in construction schedules, and the cost and difficulty of financing.

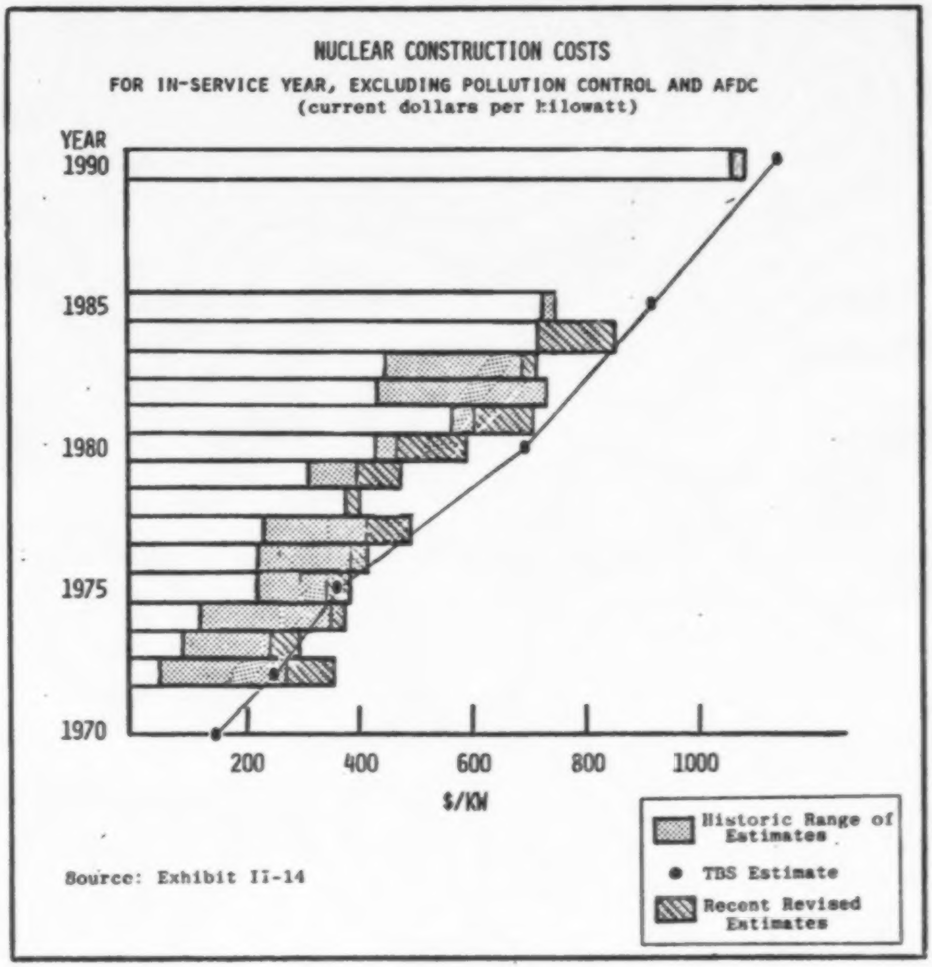
The capital costs used within this analysis are summarized in the following table for selected in-service years.

UNIT CONSTRUCTION COSTS
In-Service Year Excluding Pollution Control and AFDC
(current dollars per kilowatt)

	1972	1975	1980	1985	1990
Nuclear Steam Electric Units	$245	$367	$699	$901	$1,160
Nuclear Fuel	42	60	84	118	166
Conventional Steam Electric Units					
Coal-fired	150	211	498	698	980
Oil-fired	160	220	330	470	660
Gas-fired	90	135	275	415	580
Hydraulic Units					
Hydrolectric	350	440	650	920	1,290
Pumped Storage	116	147	215	310	430
Internal Combustion/Turbine Units	100	125	185	260	370
Transmission and Distribution	198	253	336	423	539

Source: Exhibits II-14 through II-16, and PTm (Electric Utilities)

Because there is considerable uncertainty in the projected costs of generating capacity and wide variations among forecasters, the TBS estimates should be contrasted with estimates from other sources. The curve shown on the next page indicates that the TBS estimates of nuclear plant construction costs tend to be higher than most through 1980. Comparative costs for other unit types can be found in Exhibits II-14 through II-16.



NUCLEAR CONSTRUCTION COSTS

FOR IN-SERVICE YEAR, EXCLUDING POLLUTION CONTROL AND AFDC

(current dollars per kilowatt)

Source: Exhibit II-14

These capital cost estimates reflect rates of cost escalation ranging from 7 to 15 percent in the late 1970s. In fact, the range of estimates for all units except coal indicates a projected rate of escalation of 7 percent per year throughout the 1980s. The estimates for coal-fired units, however, indicate that the current 12 percent rate of escalation will be sustained unit 1985. While the 12 percent is higher than the rate for nuclear units, the costs per kilowatt for both types have been re-examined and confirmed by industry sources. Exhibit II-17 summarizes capital cost escalation rates through 1990.

The capital costs described above are for in-service dates. However, the spending precedes the date the plant becomes operational by several years. Although the generating capacity, related transmission and distribution equipment, and nuclear fuel placed in service in any given year are determined by load growth requirements, the actual construction work begins several years prior to the in-service date. Moreover, the cash flow associated with generating plant additions generally precedes the completion of construction. Changes in the construction work in progress account generally have constituted a substantial portion of the capital expenditures by the electric utility industry in any given year.

In order to approximate the cash progress payments related to construction requirements, TBS has followed the assumption of payment schedules as outlined in Exhibit II-18. As an example, a $100 million nuclear-fueled generating unit (with an additional $15 million for nuclear fuel) placed in service in 1981 would require cash payments of:

EXAMPLE: NUCLEAR PLANT PROGRESS PAYMENTS

	Nuclear Plant	Nuclear Fuel
1976	$ 5 million	-
1977	$15 million	-
1978	$25 million	-
1979	$25 million	-
1980	$15 million	-
1981	$15 million	$15 million

Source: Exhibit II-18

Similarly, a $100 million fossil-fueled generation unit placed in service in 1981 with $100 million in related transmission and distribution equipment would require cash payments of:

EXAMPLE: FOSSIL-FUELED PLANT PROGRESS PAYMENTS

	Fossil Plant	Transmission and Distribution
1977	$ .5 million	-
1978	$20 million	-
1979	$30 million	-
1980	$30 million	-
1981	$15 million	$100 million

Source: Exhibit II-18

OPERATING AND MAINTENANCE COST FACTORS

Operating and maintenance costs, which have been the major category of electric utility industry costs, can be separated into fuel and non-fuel components. Such a separation permits a detailed analysis of fuel costs, which accounted for nearly 60 percent of utility rate increases in 1974.

Fuel Costs

As is well known, fuel prices increased dramatically in 1974, affecting every major industry, but especially the electric utility industry. Coal prices rose 68 percent over the 1973 level and oil prices jumped 137 percent. Although most observers agree that a repetition of the 1974 increases is unlikely, the complex nature of the fuel market makes prices difficult to project with any certainty.

Factors in evidence at the end of 1975 suggested that coal prices will increase at a rate faster than the rate of GNP inflation--at perhaps 10 percent through 1980 and 8 percent thereafter. Although most industry sources are reluctant to forecast coal prices, several upward pressures on prices are apparent. These are decreasing domestic oil and gas reserves; coal industry labor rate increases exceeding the GNP rate; and the potential changes in the safety requirements of OSHA and MESA, which may decrease productivity.[1] TBS has, therefore, assumed a relatively high escalation rate for the price of coal, at least through 1980.

Oil price forecasts by various observers seem to have converged on a rate of price escalation approximately equal to the GNP inflation rate. TBS has adopted that level of oil price increases for the 1976-1990 period.

Due to uncertainties regarding the extent of natural gas curtailments and the likelihood of interstate deregulation, TBS assumed in projecting gas prices that:

- Natural gas prices would equal coal prices by 1980 in dollars per million Btu, and
- Natural gas prices would equal oil prices by 1985 in dollars per million Btu.

---

[1] *OSHA: Occupational Safety and Health Administration*
MESA: Mining Enforcement and Safety Administration

These fossil-fuel price assumptions can be summarized as follows:

FOSSIL FUEL PRICE ASSUMPTIONS
(current dollars)

	1970	1975	1980	1985	1990
Coal ($/mmBtu)	$ 0.31	$ 0.79	$ 1.46	$ 2.10	$ 3.09
($/ton)	$ 7.08	$17.58	$31.78	$44.52	$65.51
Oil ($/mmBtu)	$ 0.40	$ 2.03	$ 2.69	$ 3.39	$ 4.32
($/barrel)	$ 2.45	$12.37	$16.43	$20.66	$26.37
Gas ($/mmBtu)	$ 0.27	$ 0.70	$ 1.46	$ 3.39	$ 4.32
($/mcf)	$ 0.28	$ 0.72	$ 1.50	$ 3.47	$ 4.42

Source: Exhibit II-22

Fuels for internal combustion and gas turbine (IC/GT) units were estimated by examining the relationship between fuel costs for peaking units and conventional steam electric plants, as reported in Uniform Statistical Reports. On the basis of these data, IC/GT fuel costs were estimated to be 10 percent higher than oil- and gas-fired steam electric units in terms of dollars per million Btu.

Given fossil fuel prices, total fuel costs can be obtained from the product of fuel prices, heat rates, and generation requirements.[2] TBS assumed that the average heat rate for existing units would approximate 1972 operations and that all capacity additions after 1972 would be more efficient. Thus, as post-1972 capacity additions increase in relative terms, the average heat rate will decline. The average heat rates in terms of Btu per kilowatt-hour are as follows:

---

[2] *Heat Rate: amount of heat required to generate enough steam to produce one kilowatt-hour of electricity.*

AVERAGE HEAT RATES
(Btu/kwh)

	Existing Units	Capacity Additions
Conventional Steam Electric Units		
Coal-fired	10,269	9,200
Oil-fired	11,234	9,200
Gas-fired	10,764	9,500
Internal Combustion/Turbines	14,000	10,500

Source: EEI Statistical Yearbook (1973) and TBS estimates

Non-Fuel Costs

Operating and maintenance expenses, excluding fuel have been sub-divided into those associated with generation equipment and those associated with transmission, distribution, and other production costs. With the exception of pumped storage costs, these expenses were computed from FPC data for investor-owned electric utilities on a kilowatt-hour basis.[3] These non-fuel costs are expected to inflate at the GNP rate.

---

[3] *Statistics of Privately-Owned Electric Utilities*, Federal Power Commission (1973).

Assuming that pumped storage will be most closely linked to nuclear units, operations and maintenance costs for pumped storage have been estimated from nuclear costs. It is also assumed that pumped storage has a two-thirds efficiency--that is, it will take three kilowatt-hours of off-peak power to produce two kilowatt-hours of on-peak energy.

Projections of non-fuel operating and maintenance expenses are summarized in the following table:

NON-FUEL OPERATING & MAINTENANCE EXPENSES
(mills/kwh, current dollars)

	1972	1975	1980	1985	1990
Nuclear Steam Electric Units	1.34	1.71	2.27	2.86	3.65
Conventional Steam Electric Units	1.08	1.38	1.83	2.30	2.94
Hydraulic Units					
Hydroelectric	1.15	1.47	1.95	2.45	3.13
Pumped Storage	2.01	2.56	3.40	4.28	5.46
Internal Combustion/Turbines	3.32	4.23	5.62	7.07	9.02
Transmission, Distribution and Other O/M Expenses	4.32	5.50	7.30	9.18	11.72

Source: 1972 data: Statistics of Privately Owned Utilities, FPC (1973);
1975-1990 data: Inflated at GNP rate from 1972 base.

CHAPTER 5

FINANCIAL POLICIES AND COSTS

Chapter 5 briefly describes the assumptions concerning financial policies and costs employed in the PTm projections. These financial assumptions are important because of the electric utility industry's long lead time for construction of generating plants and because of its capital intensity.

INDUSTRY STRUCTURE

The electric utility industry is the aggregation of two principal sectors which, while providing essentially the same service, differ significantly in their financial characteristics. These sectors are the private firms (i.e., investor-owned) and public agencies (i.e., Federal, state, and municipal). In terms of generating capacity, generation, direct costs of new capacity additions, and operating and maintenance costs, the investor-owned systems account for 78 percent of the U.S. total, while publicly-owned systems account for the remaining 22 percent. Because the publicly-owned systems have lower financing costs and tend to have a high percentage of hydroelectric generation, they account for only 15 percent of total operating revenues for the industry, while investor-owned systems account for approximately 85 percent.

TBS assumed that the 1974 ownership structure of the industry will be maintained throughout the projection period. Moreover, because almost 80 percent of the electric utility industry's assets are held by investor-owned companies and because there is a paucity of readily available information on the financial characteristics of those organizations in the public sector, the two segments of the private sector are modeled in detail and together serve as a basis for estimating certain characteristics of the public sector.

CAPITAL STRUCTURE AND CAPITAL COSTS

In projecting the capitalization of the industry, TBS assumed that the industry's capital structure ratios will remain relatively stable. The mix of financing for investor-owned utilities, therefore, is determined within PTm by the following constraints upon their capital structure:

- Long-term debt--no more than 55 percent,
- Preferred stock--no more than 10 percent, and
- Common equity--at least 35 percent.

To determine future financing charges in total, future interest rates and equity costs also need to be projected. The average rate of interest on long-term debt and the dividend rate on preferred stock have historically been almost the same. Recent levels of these rates, however, have been far above historical levels. In 1975, long-term mortgage bonds for electric utilities ranged roughly from 9.5 percent for Aa bonds to 12 percent for Baa bonds. Given that the prospect for major reductions in long-term inflation rates, and therefore in nominal rates of return on financial securities, is somewhat dim, TBS assumed an 11 percent rate of interest on long-term debt and dividends on preferred stock for 1975-1976, and a 10 percent rate from 1977 on.

With regard to the cost of common equity, TBS assumed that average consumer charges per kilowatt-hour will be set at levels that yield a 14 percent return on common equity. This assumption is consistent with either a target 14 percent return and no regulatory lag or a target rate in excess of 14 percent with time lags in the regulatory process. In recent years the actual return on common equity has averaged between 10 and 12 percent. However, recent indications are that regulatory agencies are beginning to adjust allowed returns upward in response to the higher rates of return demanded by investors under current inflationary conditions. In addition, TBS assumed a stable dividend payout ratio of 70 percent.

Regulatory agencies in the past have required electric utilities to capitalize a portion of the financing charges associated with the funds supporting construction work in progress. In 1972, the allowance for funds used during construction (AFDC) approximated 6.43 percent of construction work in progress. This rate has increased roughly in parallel with financing costs in recent years. TBS has used an 8 percent assumption to reflect the current practice of the industry.

Because the total revenues and costs of the public sector are computed in PTm as a fraction of the detailed private sector costs, little in the way of financial assumptions is required for the public sector. One assumption, the ratio of total financing requirements met by internal versus external sources, is relevant. TBS has followed the TAC-Finance assumption that 65 percent of total financing requirements by the public sector will be met from external sources.

ACCOUNTING PRACTICES

Internal cash generation in an industry as capital intensive as the electric utility industry depends importantly upon the accounting procedures employed. As previously mentioned, this analysis assumes that the electric utility industry is segmented into public and investor-owned firms and that the latter group of utilities is further divided into those which are required to use flow-through accounting procedures and those which normalize their tax expenses. While alternative regulatory accounting practices significantly affect reported expenses and revenue requirements, they do not affect actual taxes paid. The liberalized depreciation and investment tax credit policies allowed by the government apply equally to both groups.

TBS's projections assume a continuation of the industry's current regulatory accounting practices. In particular, it is assumed that 60 percent of the investor-owned utilities will continue to utilize flow-through accounting, while 40 percent use normalized accounting. For regulatory and financial accounting purposes, TBS assumed straight-line depreciation over 35 years. For tax purposes, depreciation figures are the maximum allowed and make use of the asset depreciation range (ADR) and the double-declining balance depreciation provisions within the tax code. An exception to the above is nuclear fuel, which is depreciated on a four-year, straight-line basis for both tax and regulatory purposes. In addition, a 4 percent investment tax credit (10 percent in 1975 and 1976) is permitted on 80 percent of capitalized expenditures.

TAXES

Taxes within PTm have been segmented into federal income tax, state and local income tax, and taxes other than on income (e.g., property and sales taxes). The tax rates assumed in developing the projections are:

	Percent
• Federal income tax rate	48.0
• State and local income tax rate	4.8
• Other taxes as a percent of revenues	10.5

Exhibit II-23 summarizes the financial assumptions described in this chapter.

Exhibit II-1

PTM SALES AND CAPACITY ASSUMPTIONS
U.S. ELECTRIC UTILITY INDUSTRY

	PEAK DEMAND (MM)	PEAK GROWTH (%)	RESERVE MARGIN (%)	CAPAB AT PEAK (MM)	YR END CAP (MM)	CAPACITY FACTOR (%)	TOTAL GENER (BIL)	GENER NOT SOLD (%)	SALES (BIL)	SALES GROWTH (%)	LOAD FACTOR (%)
1973	345.2	7.8	21.6	419.7	439.8	50.5	1855.3	8.2	1703.1	8.0	61.4
1974	350.7	1.6	30.6	457.9	476.0	46.5	1864.9	8.8	1700.8	-.1	60.7
1975	358.1	2.1	37.6	492.8	509.5	44.2	1908.2	9.0	1736.5	2.1	60.8
1976	381.3	6.5	36.4	520.0	530.6	44.8	2041.8	9.0	1858.0	7.0	61.1
1977	403.8	5.9	34.0	541.3	552.5	45.6	2160.2	9.0	1965.8	5.8	61.1
1978	426.9	5.7	32.3	564.9	578.1	46.2	2287.7	9.0	2081.8	5.9	61.2
1979	450.8	5.6	30.8	589.6	602.2	46.9	2420.3	9.0	2202.5	5.8	61.3
1980	476.0	5.6	29.4	615.9	630.9	47.6	2565.6	9.0	2334.7	6.0	61.5
1981	500.8	5.2	28.0	641.0	656.0	48.1	2701.5	9.0	2458.4	5.3	61.6
1982	526.8	5.2	26.0	663.8	678.8	48.9	2844.7	9.0	2588.7	5.3	61.6
1983	554.2	5.2	24.0	687.2	702.3	49.8	2995.5	9.0	2725.9	5.3	61.7
1984	583.0	5.2	22.0	711.3	726.3	50.6	3154.3	9.0	2870.4	5.3	61.8
1985	613.3	5.2	20.0	736.0	751.0	51.5	3321.4	9.0	3022.5	5.3	61.8
1986	645.8	5.3	20.0	775.0	790.1	51.5	3497.5	9.0	3182.7	5.3	61.8
1987	680.1	5.3	20.0	816.1	831.1	51.5	3682.8	9.0	3351.4	5.3	61.8
1988	716.1	5.3	20.0	859.3	874.4	51.5	3878.0	9.0	3529.0	5.3	61.8
1989	754.0	5.3	20.0	904.9	919.9	51.5	4083.6	9.0	3716.0	5.3	61.8
1990	794.0	5.3	20.0	952.8	967.9	51.5	4300.0	9.0	3913.0	5.3	61.8

Source: PTm (Electric Utilities)

Exhibit II-2

PTM GROSS ADDITIONS TO GENERATING PLANT INCLUDING CONVERSIONS TO COAL AND OIL

(MILLION KILOWATTS)

	TOTAL CAPACITY	TOTAL ADDTNS.	FOSSIL SUBTOTAL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1973	439.8	41.9	25.8	19.8	4.9	1.2	5.8	2.6	2.6	5.0
1974	476.0	38.1	17.7	10.2	5.8	1.7	10.5	1.0	1.0	7.9
1975	509.5	36.1	20.4	11.1	6.3	3.0	9.1	2.3	.3	4.0
1976	530.6	26.1	13.2	8.4	3.9	.9	8.3	1.3	1.5	1.8
1977	552.5	26.9	16.5	12.4	3.6	.5	5.4	2.3	.3	2.4
1978	578.1	28.7	15.0	13.3	1.7	.0	7.2	2.7	.8	3.0
1979	602.2	27.4	19.2	17.9	1.3	.0	5.5	.8	.2	1.7
1980	630.9	32.3	16.7	15.9	.8	.0	12.5	2.0	.4	.7
1981	656.0	30.6	14.4	14.4	.0	.0	10.7	1.5	.9	3.1
1982	678.8	28.6	13.4	13.4	.0	.0	10.0	1.4	.9	2.9
1983	702.3	29.4	13.8	13.8	.0	.0	10.3	1.5	.9	2.9
1984	726.3	30.0	14.1	14.1	.0	.0	10.5	1.5	.9	3.0
1985	751.0	30.8	14.5	14.5	.0	.0	10.8	1.5	.9	3.1
1986	790.1	45.4	21.3	21.3	.0	.0	15.9	2.3	1.4	4.5
1987	831.1	47.7	22.4	22.4	.0	.0	16.7	2.4	1.4	4.8
1988	874.4	50.0	23.5	23.5	.0	.0	17.5	2.5	1.5	5.0
1989	919.9	52.6	24.7	24.7	.0	.0	18.4	2.6	1.6	5.3
1990	967.9	55.3	26.0	26.0	.0	.0	19.3	2.8	1.7	5.5

Source: PTm (Electric Utilities)

Exhibit II-3

PTm TOTAL GENERATION BY FUEL TYPE INCLUDING CONVERSIONS TO COAL AND OIL

(billion kwh)

	TOTAL GENER.	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1973	1855.3	852.2	296.7	328.0	83.2	233.0	32.0	30.1
1974	1864.9	829.1	278.3	304.6	113.5	266.0	36.3	37.0
1975	1908.2	857.2	275.5	262.5	192.3	250.0	34.1	36.6
1976	2041.8	917.5	306.8	237.3	239.6	261.2	40.7	38.6
1977	2160.2	989.0	335.9	207.3	270.2	274.2	42.7	40.8
1978	2287.7	1064.3	351.5	186.3	308.6	287.1	46.4	43.4
1979	2420.3	1164.8	365.0	165.1	339.8	293.1	47.5	44.9
1980	2565.6	1261.4	361.3	142.4	404.1	301.8	49.4	45.2
1981	2701.5	1330.9	354.9	138.1	464.3	311.6	53.8	48.0
1982	2844.7	1403.7	350.0	134.4	524.6	322.7	58.3	51.0
1983	2995.5	1480.2	345.0	130.5	588.4	334.4	63.1	54.0
1984	3154.3	1560.6	339.8	126.5	655.7	346.5	68.1	57.3
1985	3321.4	1644.9	334.4	122.4	726.7	359.1	73.4	60.6
1986	3497.5	1733.8	322.8	115.9	813.1	368.4	79.3	64.3
1987	3682.8	1827.0	311.2	109.5	903.5	378.1	85.4	68.1
1988	3878.0	1924.9	299.7	103.0	998.2	388.2	91.9	72.1
1989	4083.6	2027.7	288.2	96.6	1097.3	398.9	98.7	76.2
1990	4300.0	2135.6	276.8	90.1	1201.1	410.0	105.8	80.6

Source: PTm (Electric Utilities)

Exhibit II-4

PTm TOTAL CAPACITY BY FUEL TYPE

CAPACITY REPORT

	PEAK KW	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1973	345.2	1855.3	1703.1	439.9	41.8	1.5
1974	350.7	1864.9	1700.8	476.0	38.1	2.0
1975	358.1	1908.2	1736.5	509.4	36.1	2.4
1976	381.3	2041.8	1858.0	530.5	26.1	5.0
1977	403.8	2160.2	1965.8	552.5	26.9	5.0
1978	426.9	2287.7	2081.8	578.1	28.7	3.1
1979	450.8	2420.3	2202.5	602.3	27.4	3.2
1980	476.0	2565.6	2334.7	631.0	32.3	3.3
1981	500.8	2701.5	2458.4	656.0	30.6	5.5
1982	526.8	2844.7	2588.7	678.8	28.6	5.7
1983	554.2	2995.5	2725.9	702.2	29.4	5.9
1984	583.0	3154.3	2870.4	726.2	30.0	6.0
1985	613.3	3321.4	3022.5	751.0	30.8	6.1
1986	645.8	3497.5	3182.7	790.0	45.4	6.2
1987	680.1	3682.8	3351.4	831.1	47.7	6.4
1988	716.1	3878.0	3529.0	874.4	50.0	6.7
1989	754.0	4083.6	3716.0	919.8	52.6	7.0
1990	794.0	4300.0	3913.0	968.0	55.3	7.2

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO
1973	323.3	176.3	60.7	86.2	21.1	54.5
1974	339.4	185.8	66.3	87.4	31.6	55.4
1975	357.8	196.2	72.3	89.2	40.7	57.6
1976	366.4	205.7	79.8	80.9	49.0	58.9
1977	378.4	219.3	87.4	71.6	54.5	61.1
1978	390.8	235.0	92.0	63.9	61.7	63.8
1979	407.3	255.4	95.9	56.0	67.2	64.5
1980	421.1	276.8	96.1	48.2	79.7	66.4
1981	430.5	288.5	95.2	46.7	90.4	67.8
1982	438.8	299.2	94.2	45.4	100.4	69.2
1983	447.3	310.1	93.2	44.0	110.7	70.6
1984	456.1	321.3	92.2	42.5	121.2	72.0
1985	465.1	332.9	91.2	41.0	132.0	73.5
1986	480.8	351.2	90.1	39.5	147.9	75.7
1987	497.4	370.4	89.0	38.0	164.5	78.0
1988	515.0	390.8	87.9	36.4	182.0	80.4
1989	533.5	412.1	86.8	34.7	200.4	83.0
1990	553.1	434.6	85.5	33.0	219.8	85.7

CAPACITY REPORT

	PUMPED STORAGE	IC/GT
1973	7.3	33.7
1974	8.3	41.3
1975	8.5	44.8
1976	10.0	46.2
1977	10.4	48.1
1978	11.2	50.6
1979	11.4	51.9
1980	11.8	52.0
1981	12.7	54.6
1982	13.6	56.8
1983	14.4	59.2
1984	15.3	61.6
1985	16.3	64.1
1986	17.6	68.0
1987	19.1	72.1
1988	20.6	76.4
1989	22.1	80.8
1990	23.8	85.6

Source: PTm (Electric Utilities)

Exhibit II-5

PTM FUELS CONSUMED FOR GENERATION OF ELECTRICITY
INCLUDING CONVERSIONS TO COAL AND OIL

CONVENTIONAL STEAM AND PEAKING UNITS

	TOTAL GENERATION	COAL (MM TONS)	OIL (MM BBLS)	GAS (BCF)
1973	1855.3	388.7	579.6	3689.3
1974	1864.9	376.2	547.4	3456.9
1975	1908.2	387.0	536.4	2984.0
1976	2041.8	412.7	591.9	2716.5
1977	2160.2	449.5	644.4	2394.6
1978	2287.7	488.8	675.3	2171.4
1979	2420.3	540.1	701.7	1941.2
1980	2565.6	591.2	697.1	1690.3
1981	2701.5	626.1	689.5	1654.8
1982	2844.7	663.1	685.0	1626.5
1983	2995.5	702.2	680.2	1596.2
1984	3154.3	743.7	675.5	1566.0
1985	3321.4	787.5	670.5	1534.8
1986	3497.5	827.1	655.0	1478.7
1987	3682.8	868.5	639.6	1424.1
1988	3878.0	912.2	624.6	1369.2
1989	4083.6	958.0	609.9	1315.7
1990	4300.0	1006.1	595.7	1262.3

Source: PTm (Electric Utilities)

Exhibit II-6

PTm BASELINE FINANCIAL PROJECTIONS

(constant 1975 dollars)

CONSTANT DOLLARS

	CWIP	CE	CE - CWIP	EXT FIN	OPER REV	CONS CHRG
1973	28.76	23.99	17.14	18.47	40.85	23.99
1974	28.49	20.66	20.93	15.56	50.30	29.57
1975	26.03	19.15	21.62	14.28	51.37	29.58
1976	28.81	19.25	16.47	13.42	56.56	30.44
1977	32.47	20.84	17.18	14.87	61.21	31.14
1978	34.73	21.47	19.22	15.03	65.06	31.25
1979	38.36	22.44	18.80	15.93	69.61	31.61
1980	36.81	23.44	24.99	16.30	74.03	31.71
1981	37.38	23.78	23.21	15.90	77.65	31.59
1982	40.61	25.45	22.22	17.57	82.19	31.75
1983	45.60	28.26	23.27	19.31	86.70	31.81
1984	52.48	31.31	24.44	22.16	91.56	31.90
1985	63.04	36.27	25.72	26.44	96.76	32.01
1986	67.11	40.86	36.80	30.20	102.19	32.11
1987	71.45	43.56	39.22	32.03	109.25	32.60
1988	76.07	46.44	41.81	33.84	116.74	33.08
1989	81.01	49.50	44.56	35.48	124.66	33.55
1990	86.28	52.77	47.50	37.67	133.07	34.01

CONSTANT DOLLARS

	CUMM CE	CUMM - CWIP	CUMM EX FIN	CUMM OPER	O+M	CUMM O+M
1973	23.99	0	18.47	40.85	21.58	21.58
1974	44.65	-0	34.02	91.15	28.63	50.21
1975	63.80	21.62	48.30	142.52	29.31	79.52
1976	83.05	38.09	61.72	199.08	32.46	111.97
1977	103.90	55.27	76.59	260.29	34.94	146.92
1978	125.37	74.49	91.62	325.35	37.41	184.33
1979	147.81	93.29	107.56	394.96	40.21	224.54
1980	171.24	118.27	123.86	469.00	42.76	267.30
1981	195.03	141.49	139.76	546.65	43.80	311.10
1982	220.48	163.71	157.33	628.84	46.03	357.13
1983	248.74	186.98	176.64	715.55	48.43	405.56
1984	280.05	211.41	198.81	807.10	51.00	456.56
1985	316.32	237.13	225.25	903.07	53.75	510.31
1986	357.19	273.93	255.45	1006.05	56.42	566.73
1987	400.75	313.15	287.48	1115.30	59.34	626.08
1988	447.18	354.95	321.32	1232.04	62.49	688.56
1989	496.69	399.52	356.80	1356.70	65.87	754.43
1990	549.46	447.02	394.48	1489.77	69.50	823.93

Source: PTm (Electric Utilities)

Exhibit II-7

PTm BASELINE FINANCIAL PROJECTIONS

(current dollars)

CURRENT DOLLARS

	CWIP	CE	CE - CWIP	EXT FIN	OPER REV	CONS CHRG
1973	24.72	20.62	16.65	15.87	35.10	20.61
1974	25.86	18.75	17.61	14.12	45.64	26.84
1975	26.03	19.15	18.98	14.28	51.37	29.58
1976	30.83	20.60	15.80	14.36	60.52	32.57
1977	37.00	23.75	17.57	16.95	69.75	35.48
1978	41.87	25.89	21.02	18.12	78.44	37.68
1979	48.61	28.43	21.69	20.19	88.21	40.05
1980	48.89	31.12	30.85	21.65	98.31	42.11
1981	51.98	33.07	29.98	22.11	107.96	43.92
1982	59.12	37.05	29.90	25.57	119.65	46.22
1983	69.50	43.07	32.69	29.44	132.15	48.48
1984	83.75	49.97	35.73	35.37	146.11	50.90
1985	105.32	60.61	39.03	44.18	161.67	53.49
1986	117.73	71.69	59.29	52.98	179.27	56.33
1987	131.60	80.24	66.36	59.00	201.24	60.05
1988	147.14	89.81	74.28	65.46	225.78	63.98
1989	164.52	100.53	83.15	72.06	253.16	68.13
1990	183.98	112.53	93.07	80.33	283.76	72.52

CURRENT DOLLARS

	CUMM CE	CUMM - CWIP	CUMM EX FIN	CUMM OPER	O+M	CUMM O+M
1973	0	0	0	0	18.54	0
1974	0	0	0	0	25.98	0
1975	19.15	18.98	14.28	51.37	29.31	29.31
1976	39.75	34.78	28.64	111.89	34.73	64.04
1977	63.50	52.36	45.58	181.64	39.82	103.86
1978	89.39	73.38	63.71	260.08	45.11	148.97
1979	117.82	95.07	83.90	348.29	50.95	199.91
1980	148.95	125.91	105.54	446.60	56.78	256.70
1981	182.01	155.89	127.66	554.56	60.90	317.60
1982	219.06	185.79	153.23	674.22	67.01	384.61
1983	262.13	218.48	182.67	806.36	73.81	458.42
1984	312.10	254.21	218.03	952.47	81.38	539.80
1985	372.71	293.24	262.21	1114.14	89.81	629.61
1986	444.39	352.53	315.20	1293.41	98.98	728.59
1987	524.63	418.89	374.19	1494.65	109.31	837.90
1988	614.44	493.16	439.65	1720.43	120.86	958.76
1989	714.97	576.31	511.71	1973.59	133.77	1092.53
1990	827.50	669.38	592.04	2257.35	148.20	1240.73

Source: PTm (Electric Utilities)

Exhibit II-8

BASELINE FINANCIAL PROJECTIONS

(dollar figures in billions of 1975 dollars)

	1973	1974	1977	1980	1983	1985	1990
Capital Expenditures[1]							
Total for year	$ 17.1	$ 20.9	$ 17.2	$ 25.0	$ 23.3	$ 25.7	$ 47.5
Total since 1974	-	-	53.3	118.3	187.0	237.1	447.0
Construction Work in Progress							
End of year	$ 28.8	$ 28.5	$ 32.5	$ 36.8	$ 45.6	$ 63.6	$ 86.3
External Financing							
Total for year	$ 18.5	$ 15.6	$ 14.9	$ 16.3	$ 19.3	$ 26.4	$ 37.6
Total since 1974	-	-	42.6	89.8	142.6	191.2	360.5
Operating Revenues							
Total for year	$ 40.9	$ 50.3	$ 62.2	$ 74.0	$ 86.7	$ 96.8	$133.1
Total since 1974	-	-	169.1	377.9	624.4	812.7	1,398.6
Operations and Maintenance Expenses[2]							
Total for year	$ 21.6	$ 28.6	$ 34.9	$ 42.8	$ 48.4	$ 53.8	$ 69.5
Total since 1974	-	-	96.2	217.1	355.4	460.1	773.7
Consumer Charges (mills/kwh)							
Average for year	24.0	29.6	31.4	31.7	31.8	32.0	34.0

[1] *net of CWIP increase*

[2] *excludes nuclear fuel, which is included in Capital Expenditures*

Source: PTm (Electric Utilities)

Exhibit II-9

FINANCIAL PROJECTIONS OF PREVIOUS BASELINE CONDITIONS

(dollar figures in billions of 1975 dollars)

	1973	1974	1977	1980	1983	1985	1990
Capital Expenditures[1]							
Total for year	15.2	10.6	17.4	21.1	28.6	31.9	39.4
Total since 1974	-	-	47.9	107.3	185.5	247.5	426.1
Construction Work in Progress							
End of year	21.5	20.2	29.0	37.6	47.9	53.6	68.1
External Financing							
Total for year	8.4	3.3	12.0	15.4	19.5	22.0	25.8
Total since 1974	-	-	35.9	78.0	135.0	177.7	295.1
Operating Revenues							
Total for year	43.2	46.1	57.5	69.0	81.8	90.9	114.0
Total since 1974	-	-	160.6	355.5	588.5	765.6	1,287.6
Operations and Maintenance Expenses[2]							
Total for year	19.4	21.2	28.9	35.6	41.6	45.3	54.2
Total since 1974	-	-	79.5	179.4	299.1	387.7	639.9
Consumer Charges (mills/kwh)							
Average for year	25.8	28.4	28.9	29.5	28.4	28.2	27.0

[1] *net of CWIP increase*

[2] *excludes nuclear fuel*

Source: PTm (Electric Utilities)

Exhibit II-10

FINANCIAL PROJECTIONS SUMMARY BASED ON PREVIOUS LOAD GROWTH ASSUMPTIONS AND CURRENT COST ESCALATION FACTORS

(dollar figures in billions of 1975 dollars)

	1973	1974	1977	1980	1983	1985	1990
Capital Expenditures[1]							
Total for year	$ 20.7	$ 12.8	$ 19.1	$ 23.3	$ 32.9	$ 38.2	$ 50.2
Total since 1974	-	-	52.3	115.4	204.1	277.7	500.1
Construction Work in Progress							
End of year	$ 23.4	$ 20.5	$ 29.9	$ 42.6	$ 57.7	$ 67.2	$ 92.1
External Financing							
Total for year	$ 11.8	$ 3.8	$ 14.2	$ 19.3	$ 24.1	$ 28.3	$ 35.2
Total since 1974	-	-	40.3	89.4	158.7	213.0	368.9
Operating Revenues							
Total for year	$ 46.8	$ 54.8	$ 63.5	$ 75.4	$ 91.7	$103.6	$ 132.7
Total since 1974	-	-	177.0	390.7	649.5	850.5	1,362.1
Operations and Maintenance Expenses[2]							
Total for year	$ 21.6	$ 27.7	$ 33.6	$ 39.3	$ 45.5	$ 49.5	$ 57.5
Total since 1974	-	-	93.9	206.0	337.6	434.3	704.4
Consumer Charges (mills/kwh)							
Average for year	27.5	33.3	31.6	31.8	31.4	33.5	31.0

[1] *net of CWIP increase*

[2] *excludes nuclear fuel, which is included in Capital Expenditures*

Source: PTm (Electric Utilities)

Exhibit II-11

FINANCIAL PROJECTIONS SUMMARY BASED ON HISTORIC GROWTH RATES

(dollar figures in billions of 1975 dollars)

	1973	1974	1977	1980	1983	1985	1990
Capital Expenditures[1]							
Total for year	$ 17.1	$ 20.9	$ 17.0	$ 25.3	$ 42.0	$ 49.4	$ 77.6
Total since 1974	-	-	54.9	119.5	238.2	333.1	665.0
Construction Work in Progress							
End of year	$ 28.8	$ 28.5	$ 35.5	$ 64.5	$ 81.2	$ 98.6	$147.8
External Financing							
Total for year	$ 18.5	$ 15.6	$ 16.8	$ 28.9	$ 38.8	$ 45.5	$ 66.6
Total since 1974	-	-	44.9	116.2	214.9	312.4	600.5
Operating Revenues							
Total for year	$ 40.9	$ 50.3	$ 61.2	$ 76.6	$ 96.5	$116.2	$178.2
Total since 1974	-	-	168.9	382.1	646.4	868.5	1,625.7
Operations and Maintenance Expenses[2]							
Total for year	$ 21.6	$ 28.6	$ 34.9	$ 44.4	$ 50.7	$ 58.1	$ 83.0
Total since 1974	-	-	96.5	219.6	362.1	474.5	835.0
Consumer Charges (mills/kwh)							
Average for year	24.0	29.6	30.7	31.2	31.9	33.4	36.2

[1] *net of CWIP increase*

[2] *excludes nuclear fuel, which is included in Capital Expenditures*

Source: PTm (Electric Utilities)

Exhibit II-12

FINANCIAL PROJECTIONS SUMMARY BASED ON FPC CAPACITY ADDITIONS

(dollar figures in billions of 1975 dollars)

	1973	1974	1977	1980	1983	1985	1990
Capital Expenditures[1]							
Total for year	$ 17.1	$ 20.9	$ 22.2	$ 30.2	$ 21.2	$ 25.7	$ 47.4
Total since 1974	-	-	57.1	130.5	189.6	239.7	449.3
Construction Work in Progress							
End of year	$ 28.8	$ 28.5	$ 36.3	$ 31.4	$ 45.5	$ 62.9	$ 86.1
External Financing							
Total for year	$ 18.5	$ 15.6	$ 16.3	$ 14.9	$ 18.7	$ 26.4	$ 36.6
Total since 1974	-	-	46.8	94.4	142.2	190.7	359.5
Operating Revenues							
Total for year	$ 40.9	$ 50.3	$ 61.4	$ 74.9	$ 86.7	$ 96.3	$132.5
Total since 1974	-	-	169.6	330.2	628.4	816.0	1,399.4
Operations and Maintenance Expenses[2]							
Total for year	$ 21.6	$ 28.6	$ 34.9	$ 42.3	$ 48.1	$ 53.4	$ 69.0
Total since 1974	-	-	96.6	216.0	353.1	457.1	768.4
Consumer Charges (mills/kwh)							
Average for year	24.0	29.6	31.3	32.1	31.8	31.9	33.9

[1] *net of CWIP increase*

[2] *excludes nuclear fuel, which is included in Capital Expenditures*

Source: PTm (Electric Utilities)

Exhibit II-13

CAPACITY FACTORS BY FUEL TYPE AND OWNERSHIP CATEGORY
For Representative Years

	Investor-Owned			Publicly Owned		
	1973	1980	1985	1975	1980	1985
Coal	55.1	55.0	55.0	55.1	55.0	55.0
Oil	55.7	48.0	43.0	55.7	48.0	43.0
Gas	43.4	35.0	34.5	43.4	35.0	34.5
Nuclear*	45.0	60.0	60.0	45.0	60.0	60.0
Hydro	39.0	45.5	45.5	34.0	60.0	60.0
Pumped Storage	45.1	45.1	45.1	59.4	59.4	59.4
Peakers	8.0	8.0	8.0	19.7	19.7	19.7

*Nuclear based upon 3-year power ascendency for new units averaging: 40 percent in the first year, 55 percent in the second, and 65 percent in the third and following years.

Source: 1973 figures from Edison Electric Institute 1980, 1985 projected from FPC additions, TBS demand forecast, and actual 1975 experience of several utilities.

Exhibit II-14

ESTIMATES OF CAPITAL COSTS FOR NUCLEAR UNITS

1970-1990

(in-service dates; figures in current dollars)

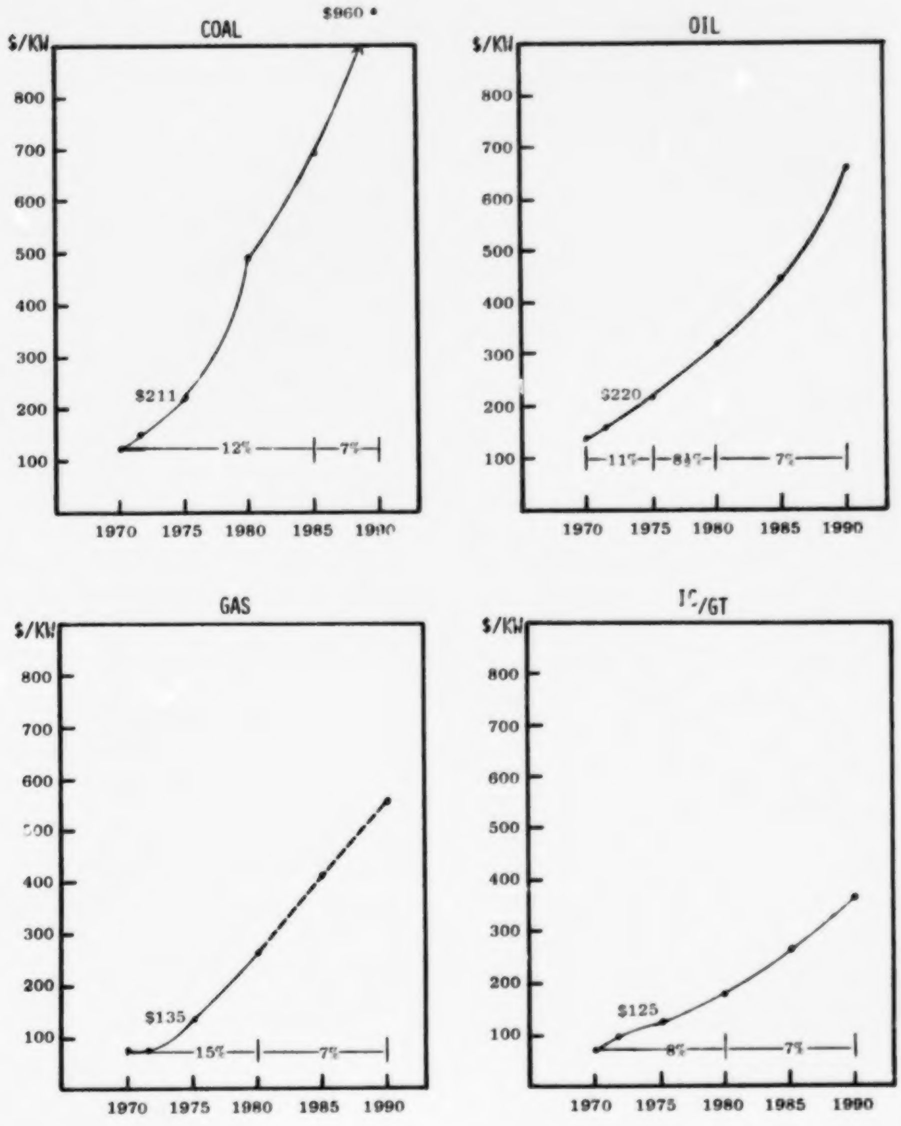
	Historic Industry	Revised Industry	TBS Estimates
Year	$/kw	$/kw	$/kw
1970	119[c]		*150*
1971		199[c]	*199*
1972	134[d], 139-148[a] 150[b], 178[f]	260[c], 352[b]	*245*
1973	146[c], 225[g]	295[b]	*280*
1974	157[c]	354[c], 367[b]	*321*
1975	209[c]	368-380[b]	*367*
1976	209-222[c]	287[b], 413[c]	*420*
1977	222[c]	490[b]	*477*
1978		370-395[c]	*542*
1979	300[c]	475[c]	*610*
1980	404[c]	458[c], 599[b], 817[i]	*699*
1981	552[d]	600-700[c]	*736*
1982	429[e], 456[c], 725[d]		*774*
1983	449[e], 558[c]	702[f]	*814*
1984		850[c]	*857*
1985	727[d]	850-900[h], 1,284[i], 1,120[j]	*901*
1986			*948*
1987			*997*
1988			*1,049*
1989			*1,104*
1990	1,042[d]		*1,160*

Sources:
- a) Electrical World, 1973
- b) Irvin C. Bupp, et al, Trends in Light Water Reactor Capital Costs in the United States; Causes and Consequences, 1974, Figure 6.
- c) Power Engineering, 1974
- d) Atomic Energy Commission, 1974
- e) Federal Power Commission, 1972
- f) Arthur D. Little, 1973
- g) Federal Power Commission--NPS, Technical Advisory Committee--Finance, The Financial Outlook for the U.S. Electric Power Industry, December 1974.
- h) Electrical World (re: Detroit Edison), 1/1/76
- i) Irvin C. Bupp, "Economics of Nuclear Power," Technology Review, 2/76
- j) Business Week (re: Con Edison), 11/17/75

Exhibit II-15

FOSSIL UNIT CAPITAL EXPENDITURE COST ASSUMPTIONS
1970 - 1990

(in-service dates, figures in current dollars)



Source: FPC, Electrical World, EEI, U.S. Atomic Energy Commission, coal prices also reflect actual 1975 experience and projections for selected utilities.

Exhibit II-16

ESTIMATES OF CAPITAL COSTS FOR FOSSIL-FUELED AND HYDRAULIC UNITS

1970 - 1990

(in-service dates; figures in current dollars)

	Fossil Fuel						IC/GT		Hydro		Pumped Storage	
	Coal		Oil		Gas							
	Industry Estimates	TBS	Industry Estimates	TBS	Industry Estimates	TBS	Industry Estimates	TBS	Industry Estimates	TBS	Industry Estimates	TBS
Year	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw	$/kw
1970		120		140		80	90[f]	90	118-381[e]	300	70-136[e]	100
1972	151-170[a]	150	145-163[a]	160	87-96[a]	90	100[a]	100		350		116
1975	196[c], 250[b], 327[f]	211	215[f]	220		135	110-125[f]	125		440		145
1976	474[h]	236		240		155		135		475		160
1978		342		280		210	155-165[f]	160		555		185
1979	800[i]	413		300		240		170		600		200
1980	310[b], 450[c], 488[j]	498		330		275		185		650		215
1981	362-378[d]	533	337-352[d]	-	310[d]	-		200		700		235
1983	588[g]	610	389[g]	-		-		230		800		270
1984	638[c]	653		-		-		245		860		290
1985	560[d], 722[j], 800[i]	698	463[d]	-		-		260		920		310
1990	740[d], 950[c]	980	664[d]	-		-		370		1,290		430

Sources:

a) Electrical World, 1973
b) Irvin C. Bupp, et al, Trends in Light Water Reactor Capital Costs in the United States: Causes and Consequences, 1974, Figure 6.
c) Power Engineering, 1974
d) Atomic Energy Commission, 1974
e) Federal Power Commission, 1972
f) Federal Power Commission--NPS, Technical Advisory Committee--Finance, The Financial Outlook for the U.S. Electric Power Industry, 12/74
g) Arthur D. Little, 1973
h) Electrical World (re: Buckeye Power) 1/15/76, includes pollution control costs
i) Electrical World (re: No. Indiana Pub. Service, Detroit Edison) 1/1/76
j) Irvin C. Bupp, "Economics of Nuclear Power," Technology Review, 2/76

Exhibit II-17

IMPLICATIONS OF INDUSTRY PROJECTIONS OF CAPITAL COSTS
IN TERMS OF ESCALATION RATES
1972 - 1990
(percent per year)

	Fossil Fuel			IC/GT	Hydro	Pumped Storage	Nuclear
Year	Coal	Oil	Gas				
1972	12.0	11.0	15.0	8.0	8.0	8.0	14.4
1973	12.0	11.0	15.0	8.0	8.0	8.0	14.4
1974	12.0	11.0	15.0	8.0	8.0	8.0	14.4
1975	12.0	11.0	15.0	8.0	8.0	8.0	14.4
1976	20.5	8.5	15.0	8.0	8.0	8.0	13.6
1977	20.5	8.5	15.0	8.0	8.0	8.0	13.6
1978	20.5	8.5	15.0	8.0	8.0	8.0	13.6
1979	20.5	8.5	15.0	8.0	8.0	8.0	13.6
1980	7.0	8.5	15.0	8.0	8.0	8.0	5.2
1981	7.0	-	-	7.0	7.0	7.0	5.2
1982	7.0	-	-	7.0	7.0	7.0	5.2
1983	7.0	-	-	7.0	7.0	7.0	5.2
1984	7.0	-	-	7.0	7.0	7.0	5.2
1985	7.0	-	-	7.0	7.0	7.0	5.2
1986	7.0	-	-	7.0	7.0	7.0	5.2
1987	7.0	-	-	7.0	7.0	7.0	5.2
1988	7.0	-	-	7.0	7.0	7.0	5.2
1989	7.0	-	-	7.0	7.0	7.0	5.2
1990	7.0	-	-	7.0	7.0	7.0	5.2

Source: Derived from annual industry capital cost estimates shown in Exhibits II-14 and II-16.

Exhibit II-18

PATTERN OF CASH FLOWS FOR CAPITAL PROJECTS
ANNUAL EXPENDITURE OF FUNDS (EXCLUDING AFDC)
(percent per year)

	T-5	T-4	T 3	T-2	T-1	T (In-Service Year)
Fossil Steam Plants	-	5%	20%	30%	30%	15%
Nuclear Plants	5	15	25	25	15	15
Nuclear Fuel	-	-	-	-	-	100
Hydro Plants	5	15	20	20	25	15
Pumped Storage Plants	5	15	20	20	25	15
IC/GT Plants	-	-	-	20	40	40
Transmission & Distribution	-	-	-	-	-	100
Pollution Control Capital Equipment	-	-	-	20	40	40

Source: TBS estimates based on examination of representative utility company expenditures.

Exhibit II-19

FORECASTS OF ELECTRIC DEMAND GROWTH
(kWh sales in trillions; implied growth percent)

	1972	1975	1977	1978	1980	1985	1990	1995	2000
Electrical World 9/74	1.58	1.86	2.11	2.23	2.50	3.24	4.20	5.70	
IGR*	-	5.6			6.1	5.3	5.3	6.3	
Electrical World 9/75	1.58	1.72	2.02	2.15	2.37	3.15	4.01	5.27	
IGR*	-	8.2			6.4	6.5	5.8		
National Electric Reliability Council 4/74	1.58	2.17	2.53	2.71	3.12	4.40			
IGR*	-	11.2			7.5	7.1			
Temple, Barker & Sloane, Inc.*** 7/75	1.58	1.74			2.34	3.02	3.95		
IGR*	-	5.0			6.3	5.6	5.5		
NPS - TAC Finance 11/74									
Historic	1.58	1.92		2.27	2.71	3.91	5.39		
IGR*	-	6.7			7.1	7.6	6.6		
Moderate	1.58	1.83		2.31	2.58	3.55	4.64		
IGR*	-	5.0			7.1	6.6	5.5		
FEA Project Independence 11/74									
$7 Oil BAU W/Cons.	1.60		2.20		2.53**	3.37			
IGR*	-		6.6		5.9	5.9			
$7 Oil BAU W/O Cons.	1.60		2.26		2.67**	3.72			
IGR*	-		7.2		6.6	6.9			
$7 Oil ACC W/Cons.	1.60				2.53**	3.34			
IGR*	-				5.9	5.7			
$7 Oil ACC W/O Cons.	1.60				2.67**	3.69			
IGR*	-				6.6	5.7			
$11 Oil BAU W/Cons.	1.60		2.13		2.46**	3.25			
IGR*			5.9		5.6	5.7			
$11 Oil BAU W/O Cons.	1.60		2.15		2.59**	3.62			
IGR*	-		6.1		6.2	6.9			
$11 Oil ACC W/Cons.	1.60				2.44**	3.20			
IGR*	-				5.4	5.6			
$11 Oil ACC W/O Cons.	1.60				2.59**	3.56			
IGR*	-				6.2	6.6			
NPS - Task Force on Forecast Review 8/73	1.58				3.17**	4.44	5.85	7.60	10.18
IGR*	-				9.1	7.0	5.7	5.4	6.0

**The implied growth rate is calculated whenever possible on a five-year incremental basis. For all studies but FEA's, a 1972 base of 1,577 billion kWh sales is assumed. FEA assumes a 1972 base of 1,597 billion kWh.*

***An implied growth of 1972-1980 has been calculated.*

****Using Electrical World 9/74 assumptions*

BAU = Business as usual
ACC = Accelerated
W/Cons. = With conservation
W/O Cons. = Without conservation

Sources: National Electric Reliability Council 4/1/74
Electrical World - 24th AEI Forecast 9/73
Electrical World - 25th AEI Forecast 9/74
National Power Survey - TAC Finance 11/74
National Power Survey - Task Force on Forecast Review 8/73
Federal Energy Administration - Project Independence 11/74

Exhibit II-20

ELECTRICAL WORLD PROJECTIONS[1]

TOTAL SALES, SYSTEM OUTPUT, PEAK LOAD, CAPABILITY, AND MARGIN

	Total Sales (bill. kWh)	Total Output (bill. kWh)	Annual Non-Coin Peak (mill. kW)	Capability At Peak (mill. kW)	Gross Peak At Margin (%)
1963	830.8	924.0	161.3*	210.6*	30.2*
1964	890.4	989.2	175.4	217.1	23.7
1965	953.4	1,062.7	186.8	229.6	22.9
1966	1,039.0	1,155.7	203.9	241.5	18.4
1967	1,107.0	1,224.5	214.0	258.8	20.8
1968	1,202.3	1,330.4	238.6	279.8	17.2
1969	1,307.2	1,449.6	258.3	301.2	16.6
1970	1,391.4	1,540.3	275.4	327.8	18.7
1971	1,466.4	1,617.5	293.1	354.6	20.9
1972	1,577.7	1,754.9	320.2	383.0	19.6
1973	1,703.2	1,878.5	345.1	417.4	20.9
			Forecast		
1974	1,738.7	1,923.0	360.6	455.5	26.2
1975	1,864.1	2,061.8	386.5	493.6	27.7
1976	1,994.1	2,205.4	411.6	527.9	28.2
1977	2,109.5	2,333.1	435.9	553.6	26.9
1978	2,233.3	2,470.0	460.7	578.8	25.1
1979	2,361.9	2,612.3	486.5	600.2	23.3
1980	2,504.3	2,769.8	513.6	624.4	21.5
1981	2,608.8	2,885.3	535.6	647.6	20.9
1982	2,753.9	3,045.8	564.4	673.8	19.3
1983	2,910.7	3,219.2	595.6	706.3	18.5
1984	3,070.5	3,396.0	625.6	742.7	18.7
1985	3,241.5	3,585.1	661.2	780.7	18.0
1990	4,195.5	4,640.2	848.9	1,002.6	18.1
1995	5,695.4	6,299.1	1,143.2	1,349.0	18.0

**Peak in winter for 1963 but in summer after 1963 until 1990 when electric heating could shift peaks to winter.*

Source: Edison Electric Institute; Federal Power Commission: Electrical World

---

[1] Table reprinted from Electrical World Magazine, September 15, 1974
25th AEI Forecast, Pg. 54.

Exhibit II-21

COAL AND OIL CONVERSIONS
1975-1980

	Coal Capacity (million kw)	Oil Capacity (million kw)
Baseline Conversions		
Gas to Coal	9.2	-
Gas to Oil	-	26.25
Other Conversions Before Clean Air Act		
Oil to Coal	11.1	(11.1)
Subtotal	20.3	15.15
Conversions After Clean Air Act		
Oil to Coal	9.5	(9.5)
Gas to Coal	9.2	-
Gas to Oil	-	26.25
Total	18.7	18.75

Source: Environmental Protection Agency;
Federal Power Commission data;
Foster Associates, Inc., August 1975

Exhibit II-22

FUEL COST ASSUMPTIONS
1974-1990
(current dollars)

		Coal		Oil		Gas		Peakers[a]
		$/Ton	$/mmBtu	$/bbl	$/mmBtu	¢/mcf	$/mmBtu	$/mmBtu
Reported	1971[b]	$8.18	$.363	$3.41	$.555	29.1¢	$.299	.61
	1972[b]	8.69	.384	3.78	.621	31.1	.319	.68
	1973[b]	9.32	.419	4.77	.783	35.2	.360	.86
	1974[b]	14.81	.678	11.21	1.832	51.2	.501	2.02
Projected	1975	17.58[c]	.79	12.37[e]	2.03[e]	72.0[f]	.70[f]	2.23
	1980	31.78	1.46[d]	16.43	2.69	150.0	1.46	2.96
	1985	44.52	2.10	20.66	3.39	347.0	3.39	3.73
	1990	65.51	3.09	26.37	4.32	442.0	4.32	4.76

Sources:

[a] Fuel costs for peaker units estimated at 1.1 times oil cost, based on a sample of seven utility companies across the country.

[b] EEI, 1974 Statistical Yearbook, Table 42S.

[c] Assuming average heat content of coal declining from 11,125 Btu/lb. in 1973-1975 to 10,600 in 1985.

[d] Assuming 1976 price of $1.00 per mmBtu, escalation at 10 percent per year 1977-1980, and escalation of 8 percent per year 1981 and later.

[e] Projected from forecast GNP rate of inflation from Chase Econometric Associates, Inc. through 1985 and 5 percent per year 1986-1990.

[f] Estimated to escalate from 1974 level to equal cost of coal by 1980 and cost of oil by 1985 on a $/mmBtu basis.

Exhibit II-23

FINANCIAL ASSUMPTIONS

(percent)

	1975	1980	1985	1990
Capital Costs				
Interest Rate, Long-Term Debt (%)	11.0	10.0	10.0	10.0
Return on Equity	14.0	14.0	14.0	14.0
Dividend Rate, Preferred Stock (%)	11.0	10.0	10.0	10.0
Capital Mix				
Public Sector:				
% Financing from Internal Sources	35.0	35.0	35.0	35.0
Private Sector:				
Minimum % Common Equity	35.0	35.0	35.0	35.0
Minimum % Common + Preferred	45.0	45.0	45.0	45.0
Tax Rates				
Federal Income Tax	48.0	48.0	48.0	48.0
State Income Tax	4.8	4.8	4.8	4.8
Other Taxes, on Operating Revenues	10.5	10.5	10.5	10.5
Investment Tax Credit	10.0	4.0	4.0	4.0
% Plant Eligible for Investment Tax Credit	80.0	80.0	80.0	80.0

Source: Federal Power Commission, Statistics on Privately Owned Electric Utilities, 1972, 1973.

Exhibit II-24

GNP DEFLATOR
FOR USE IN CONSTANT DOLLAR ANALYSIS

Year	GNP Deflator (1975=100)	INFLATION RATES Annual GNP Inflation Rate	Pollution Control Equipment	Pollution Control O&M
1971	141.4			
1972	146.1	3.3	-	-
1973	154.3	5.6	-	-
1974	170.0	10.2	-	-
1975	100.0	9.5	-	-
1976	107.0	7.0	8.0	7.0
1977	114.0	6.5	8.0	6.5
1978	120.6	5.8	7.0	5.8
1979	126.7	5.1	7.0	5.0
1980	132.8	4.8	7.0	5.0
1981	139.0	4.7	7.0	5.0
1982	145.6	4.7	7.0	5.0
1983	152.4	4.7	6.0	5.0
1984	159.7	4.8	6.0	5.0
1985	167.1	4.6	6.0	5.0
1986-2000	-	5.0	5.0	5.0

Source: Deflator and GNP inflation rates from Chase Econometric Associates, Inc., recomputed to 1975 base year; inflation rates for pollution control estimated at GNP rate for O/M and 1.5 to 2.0 points above GNP for capital equipment.

Exhibit II-25

INCOME STATEMENT FOR INVESTOR-OWNED ELECTRIC UTILITIES

(BILLIONS OF CURRENT DOLLARS)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
OPERATING REVENUE	43.7	51.4	59.3	66.7	75.0	83.6	91.8	101.7	112.3	124.2	137.4
-OPER. + MAINT. EXP.	23.1	27.4	31.4	35.5	40.1	44.7	48.0	52.8	58.2	64.1	70.8
-O/M EXP. - THERMAL	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
-O/M EXP. - CHEMICAL	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
-TAXES (OTHER)	3.7	4.4	5.0	5.7	6.4	7.1	7.8	8.6	9.5	10.6	11.7
-DEPRECIATION - PLANT	3.9	4.3	4.7	5.2	5.7	6.4	7.1	7.8	8.5	9.4	10.3
-DEPRECIATION - NUC FUEL	.3	.5	.7	.9	1.0	1.1	1.4	1.7	2.0	2.4	2.8
+AFDC	1.7	1.8	2.2	2.5	2.9	3.1	3.2	3.5	4.1	4.9	6.0
EBIT	14.3	16.7	19.5	21.9	24.6	27.3	30.7	34.3	38.1	42.6	47.9
-INTEREST	4.9	5.7	6.6	7.5	8.5	9.7	10.8	12.1	13.6	15.4	17.7
EBT	9.4	11.0	13.0	14.4	16.0	17.7	19.9	22.2	24.5	27.1	30.2
-TAXES (INCOME)	3.3	4.1	4.9	5.5	6.1	6.8	7.8	8.8	9.7	10.6	11.6
+ITC	.7	.6	.3	.4	.4	.5	.5	.5	.5	.6	.6
NET INCOME	6.8	7.5	8.3	9.3	10.3	11.4	12.6	13.9	15.4	17.1	19.3
-DIVIDENDS (PREF)	.8	.9	1.1	1.3	1.4	1.6	1.8	2.1	2.3	2.7	3.1
-DIVIDENDS (COMM)	4.2	4.6	5.1	5.6	6.2	6.8	7.5	8.3	9.1	10.1	11.4
RETAINED EARNINGS	1.8	2.0	2.2	2.4	2.7	2.9	3.2	3.5	3.9	4.3	4.9
COVERAGE RATIOS											
EBIT/INTEREST	2.9	2.9	3.0	2.9	2.9	2.8	2.8	2.8	2.8	2.8	2.7
EBIT/INT + PFD DIV	2.5	2.5	2.6	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.3

Source: PTm (Electric Utilities)

Exhibit II-26

BALANCE SHEET FOR INVESTOR-OWNED ELECTRIC UTILIES

(BILLIONS OF CURRENT DOLLARS)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
LONG TERM ASSET ACCOUNTS											
GROSS PLANT IN SERVICE	138.8	150.5	163.5	179.0	194.9	217.4	239.1	260.4	283.5	308.6	335.8
-ACCUM. DEPRECIATION	34.3	38.6	43.4	48.6	54.3	60.7	67.7	75.5	84.1	93.5	103.7
NET PLANT IN SERVICE	104.5	111.8	120.2	130.4	140.6	156.8	171.4	184.9	199.5	215.2	232.1
+NUC. FUEL (NET)	2.6	3.1	3.4	3.7	4.1	4.9	5.8	6.6	7.5	8.5	9.6
+CWIP	20.7	24.5	29.4	33.3	38.7	39.0	41.4	47.1	55.3	66.5	83.5
NET ELECTRIC PLANT	127.9	139.5	152.9	167.4	183.3	200.6	218.5	238.5	262.2	290.2	325.2
LONG TERM LIABILITY ACCOUNTS											
DEFERRED ITEMS	4.9	5.7	6.3	7.0	7.7	8.5	9.3	10.2	11.1	12.1	13.1
LONG TERM DEBT											
POST 1974	25.9	33.8	43.1	52.8	63.8	75.4	87.3	101.3	116.8	135.6	158.5
TOTAL	70.6	77.5	85.7	94.7	104.7	115.5	126.6	139.1	153.8	171.4	193.4
PREFERRED STOCK											
POST 1974	2.2	3.4	4.9	6.6	8.4	10.3	12.4	14.6	17.3	20.5	24.5
TOTAL	12.8	14.0	15.5	17.2	19.0	20.9	23.0	25.2	27.9	31.1	35.1
OWNERS EQUITY											
POST 1974 CASH ISSUES	8.3	10.7	13.8	17.1	20.8	24.7	28.6	33.0	38.5	45.3	54.4
POST 1974 RETAINED EARN.	4.8	6.8	9.0	11.4	14.0	17.0	20.2	23.7	27.6	32.0	36.8
TOTAL	44.7	49.1	54.4	60.1	66.4	73.3	80.4	88.3	97.7	108.9	122.9
TOTAL CAPITALIZATION	127.8	140.4	155.4	171.7	189.8	209.4	229.6	252.3	279.2	311.0	351.1
TOTAL LONG TERM LIABILITIES	132.6	146.1	161.7	178.7	197.5	217.9	239.0	262.5	290.3	323.1	364.2

Source: PTm (Electric Utilities)

Exhibit II-27

APPLICATIONS AND SOURCES OF FUNDS FOR INVESTOR-OWNED ELECTRIC UTILITIES

(BILLIONS OF CURRENT DOLLARS)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
APPLICATIONS OF FUNDS											
CAPITAL EXPEND. + AFDC	16.9	18.2	21.1	23.1	25.5	27.9	29.6	33.1	38.4	44.6	54.2
+REFUNDINGS	1.7	1.0	1.0	.7	1.0	.9	.7	1.5	.8	1.2	.9
TOTAL APPLICATIONS	18.6	19.3	22.1	23.9	26.5	28.8	30.3	34.6	39.1	45.8	55.1
SOURCES OF FUNDS											
INTERNAL GENERATION											
RETAINED EARNINGS	1.8	2.0	2.2	2.4	2.7	2.9	3.2	3.5	3.9	4.3	4.9
+DEPRECIATION-PLANT	3.9	4.3	4.7	5.2	5.7	6.4	7.1	7.8	8.5	9.4	10.3
+DEPRECIATION-NUC. FUEL	.3	.5	.7	.9	1.0	1.1	1.4	1.7	2.0	2.4	2.8
+DEFERRALS	.9	.8	.7	.7	.7	.9	.9	.9	1.0	1.0	1.0
TOTAL	6.9	7.6	8.3	9.2	10.1	11.3	12.6	13.9	15.4	17.1	19.0
EXTERNAL FINANCING											
LONG-TERM DEBT	8.2	8.0	9.2	9.7	10.9	11.7	11.9	14.0	15.5	18.7	22.9
+STOCK (PREF)	1.2	1.3	1.5	1.6	1.8	2.0	2.0	2.3	2.7	3.2	4.0
+STOCK (COMM)	2.3	2.4	3.1	3.3	3.7	3.9	3.9	4.4	5.5	6.8	9.1
TOTAL	11.7	11.7	13.8	14.7	16.4	17.5	17.8	20.7	23.7	28.7	36.1
TOTAL SOURCES	18.6	19.3	22.1	23.9	26.5	28.8	30.3	34.6	39.1	45.8	55.1
CUM. EXTERNAL FINANCING	36.3	48.0	61.8	76.5	92.9	110.5	128.2	148.9	172.6	201.4	237.4

Source: PTm (Electric Utilities)

APPENDIX II-A

PTm(ELECTRIC UTILITIES) RESEARCH METHODOLOGY

This appendix on research methodology consists of a non-technical overview of the logical structure of the computer model, PTm(Electric Utilities), used to derive the projections discussed and analyzed in the text of this report. The PTm model is an extension of a model developed by Drs. Howard W. Pifer and Michael L. Tennican of Temple, Barker & Sloane, Inc. to provide projections for the Technical Advisory Committee on Finance (TAC-Finance) to the 1973-1974 National Power Survey.[1]

In broad terms, PTm has three main logical components, which may conveniently be labeled the environmental, physical, and financial modules. As shown in Exhibit II-A-1, it is assumed that general economic conditions and other factors outside the model determine the demand for electricity. Consumer's peak and average demand, the industry's policy with respect to reserve margins, and the equipment, power drain, and generating efficiency implications of pollution control requirements combine to determine the industry's physical plant, equipment, fuel, and labor requirements. These physical requirements and the relevant factor costs, which are also influenced by economic considerations external to PTm, combine to determine the consequences of building and operating the capacity needed to meet consumer demand.

---

[1] *Drs. Pifer and Tennican gratefully acknowledge the counsel and assistance of a number of individuals from industry, the Federal Power Commission, and various financial institutions associated with the TAC-Finance--especially Messrs. John Childs, Gordon Corey, Fred Eggerstedt, Robert Fortune, John Glover, Rene Males, John O'Connor, and Robert Uhler.*

Preceding page blank

These capital asset and operating cash requirements are met in part by revenues collected from the users of electrical energy and in part by external financing. The amount of cash provided by operations at any moment is influenced by regulatory policy (in effect via the allowed revenue per kilowatt-hour), by tax policy (via the effective rate of taxation after consideration of depreciation tax shields, investment tax credits, etc.), and by the cost of capital raised in prior periods. Any shortfall between cash needs and the cash provided by operations is met by recourse to the capital markets.

Exhibit II-A-1 omits a number of interactions and feedbacks, two of which are notable. First, if external financing is to be available, regulatory policy must be such as to allow revenues per kilowatt-hour sufficient to yield returns to capital that are adequate in light of prevailing capital market conditions, tax policy, and pollution control requirements, all of which may have an impact on the cost of electrical power and hence on demand. As a second illustration, because the financial characteristics of the electric utility industry and of individual utilities may be considerations in the drafting and administration of pollution control legislation, pollution control policy in part determines and in part is determined by the industry's financial profile.

ENVIRONMENTAL MODULE

The model's environmental module has as its primary function the inputting of assumptions concerning future growth in the demand for power, current and future pollution control requirements, equipment and operating costs, etc. The implications of these policy, economic and technical assumptions are then determined in the physical and financial modules of PTm. PTm is programmed so as to be able to test a wide variety of policy alternatives through changes in input data. In testing alternative policies about the coverage and time phasing of water pollution control requirements, however, modifications to the logical structure of the model itself were required, so that a series of slightly different models actually were used to make the projections set out in the body of the report. Nonetheless, for simplicity we shall in the following speak of PTm as a single model rather than as a set of related models.

PHYSICAL PLANT AND EQUIPMENT MODULE

The primary relationships determining the industry's physical plant and equipment requirements are shown in Exhibit II-A-2. Consistent with the assumption that demand will be met, the industry's gross generation capacity in service at any moment is determined by the level of demand, the industry's policy with respect to capacity reserves, and the efficiency impact and operation power drain of pollution control equipment. These current capacity requirements and the rate of retirement of old generating units together determine the amount of generating capacity additions necessary for meeting current demand. With the inclusion of the pollution control equipment required for generating capacity currently in service, the additions to in-service plant and related equipment are fully specified in physical terms.

Given the long time lags involved in constructing new generating capacity, the industry's plant and equipment construction at any moment typically includes significant amounts of work in progress so as to meet future demand as it materializes. As is shown in Exhibit II-A-2, future demand, future reserve factors, future pollution control requirements, and future retirements--together with the lags in construction--determine the plant and equipment additions that are related to future demand, i.e., construction in progress. It should be noted that because the time span between ordering and placing generating capacity in service is radically different for peaking units, fossil-fueled baseload plants, and nuclear units, PTm computes construction work in progress for nuclear and for non-nuclear plants on different time schedules. Thus average construction lags are themselves a function of the assumed future mix of these various types of generating plants. It might also be noted that PTm is designed to accept assumptions about the relative proportions of nuclear and fossil additions that change over time.

FINANCIAL MODULE

For expositional purposes it is convenient to divide PTm's financial module into three segments, dealing with:

- uses of funds,
- sources of funds, and
- revenues, expenses, and profits.

USES OF FUNDS

The industry's uses of funds depicted in Exhibit II-A-3 are determined primarily by the physical plant and equipment required to meet current and future demand and by the cost per unit of this equipment. A second use is the allowance on funds tied up in plant and equipment in the process of construction. For simplicity, PTm assumes that the industry's net working capital remains constant, so that changes in working capital appear neither as a use nor as a source of funds. Given the miniscule size of such working capital changes in comparison to the industry's major sources and uses of funds, such a simplifying assumption is unlikely to introduce appreciable error in the absence of fundamental structural changes in the industry's current assets and payables accounts or in its usage of short-term debt.

Exhibit II-A-3 shows that once the total physical amounts of plant and equipment required to meet current and future demand and the proportions of those amounts accounted for by nuclear and fossil-fueled plants are determined, the crucial input assumptions required to convert these physical quantities into financial terms are the cost per unit of each type of asset and the schedule of payments required by contractors while such plant and equipment are under construction.

SOURCES OF FUNDS

In the case of the private sector of the electric utility industry, sources of funds consist of two major elements:

- funds provided by operations, and
- external financing.

Funds provided by operations are in turn the sum of three internal sources:

- depreciation ,
- tax deferrals, and
- retained earnings.

For the public sector, it is simply assumed that a percentage of total funds used is met from internal sources. As is shown in Exhibit II-A-4a, any shortfall between total uses and internal sources is met through external financing.

Exhibit II-A-4b shows these same relationships in a format that is slightly different and that shows how the private sector's total required external financing and capital structure and dividend policies combine to determine:

- cash issues of preferred stock ,
- gross cash offerings of debt, and
- cash issues of common stock.

REVENUES AND RELATED VARIABLES

The third segment of the financial module determines total industry revenues, expenses, profits, and related statistics such as price per kilowatt-hour and interest coverage ratios. The output variables of this revenues segment serve in many instances as inputs to other segments. For example, the depreciation expense figure computed in the revenue segment is an input to the sources of funds segment. Conversely, certain of the input variables to the revenue segment are based on the output from the sources and uses segment of the financial module (e.g., plant and equipment expenditures provide the base for computing depreciation expense). The structure of the revenue segment and the interactions between this segment and other parts of the total model are depicted in Exhibit II-A-5.

As shown at the top of Exhibit II-A-5, profits available for common stockholders are assumed to be determined completely by the amounts of the industry's common equity capital and by a rate of return on equity set by regulatory policy.[2] As a consequence of this assumption, revenues and prices per kilowatt-hour of electricity are determined by required profits, other capital charges, and operating expenses.

Earnings before interest and taxes (EBIT) are simply the sum of EBT and interest expense and are computed by the same general process used for preferred dividends. The resultant EBIT figure constitutes one of the five main determinants of revenues.

The second determinant of revenues, depreciation and amortization of plant and equipment, is a variable related to the amount of plant and equipment in service. Presuming that taxes other than on income consist primarily of property taxes, a third determinant of revenue, other taxes, is also related to the amount of plant and equipment in service. Plant and equipment requirements are in turn determined by both current demand and pollution control policy.

---

[2] *It should be noted that "policy" is a term intended to comprise the effect of both the target rates of return set by individual regulatory bodies and the administrative lags involved in adjusting prices per kilowatt-hour so as to achieve such target returns.*

Current consumer demand and the power drains and operating efficiency losses associated with pollution control equipment combine to determine the level of operating and maintenance expenses. This latter expense figure is the fourth determinant of revenues.

Future consumer demand and pollution control requirements also determine future in-service plant and equipment requirements and hence determine the amount of construction currently in progress. The amount of construction in progress in turn determines the allowance for funds used during construction, which is another non-cash item, but which also affects--this time diminishes--the level of revenues required to achieve a given level of profit as determined by regulatory accounting procedures. This allowance on construction funds variable is the fifth and last major determinant of revenues.

Net profit is simply the sum of profits available for common stock and preferred dividends. The amounts of preferred dividends are determined by the amounts of preferred equity capital and the average dividend rate on the industry's outstanding preferred stock. The dividend yield on new preferred stock issues--and hence the average yield--is in turn determined over time by the reaction of the capital market to the industry's offerings.

Earnings before income taxes (EBT) are then set at a level such that EBT minus taxes will be equal to the required net profit figure. The tax expense figures (or equivalently, the effective tax rate) is itself a function of the EBT figure, which is computed in accordance with regulatory accounting procedures, and several other factors. The calculations are somewhat complicated first because various special features of the tax code (e.g., provisions allowing investment tax credits and accelerated depreciation) and of regulatory accounting (e.g., the creation of allowances for funds used during construction as non-cash credits to income) must be taken into account. As a consequence of these differing provisions, taxable EBT and regulatory EBT may--and typically do--differ. Second, as mentioned earlier, there exist two substantially different regulatory methods for determining the tax expense figure to be associated with EBT. Normalizing accounting gives rise to deferred taxes, which is a non-cash charge against income but which nonetheless constitutes an accounting expense to be covered by revenues if accounting profits to stockholders are to reach prescribed levels.

A Concluding Comment

As has been outlined above, the operating, financial, tax, regulatory, and accounting relationships and constraints relevant to making economic and financial projections for the industry are individually rather simple. However, the number of these relationships and constraints is so great as to dictate the use of a computer model such as PTm. Moreover, because of interactions among the various industry relationships and constraints, attempts to reduce the number of factors through shortcut approximations are hazardous. Furthermore, such shortcuts, even if based on careful econometric analyses of historical data, tend to preclude an examination of the implications of structural and policy changes.

PTm was designed not only to compute rapidly the implications of any given set of assumptions about the future, but also to facilitate the examination of structural and policy changes. Thus, the model is able conveniently to accept input assumptions for over 100 variables, such as the current level of and future changes in: the industry's peak demand; reserve margins; the mix of nuclear and non-nuclear capacity additions; unit costs of generating plants, transmission and distribution capacity, thermal and chemical pollution equipment, etc. PTm then generates projections for a variety of physical and financial variables, including: capacity figures for each of the major segments of the industry; energy losses resulting from thermal water pollution control standards; income statements, balance sheets, funds flows, and reconciliations of regulatory and Internal Revenue Service income tax expense figures and summary statistics such as interest coverage figures.

Exhibit II-A-1

INTERACTIONS BETWEEN THE ENVIRONMENT AND THE PHYSICAL AND FINANCIAL CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY

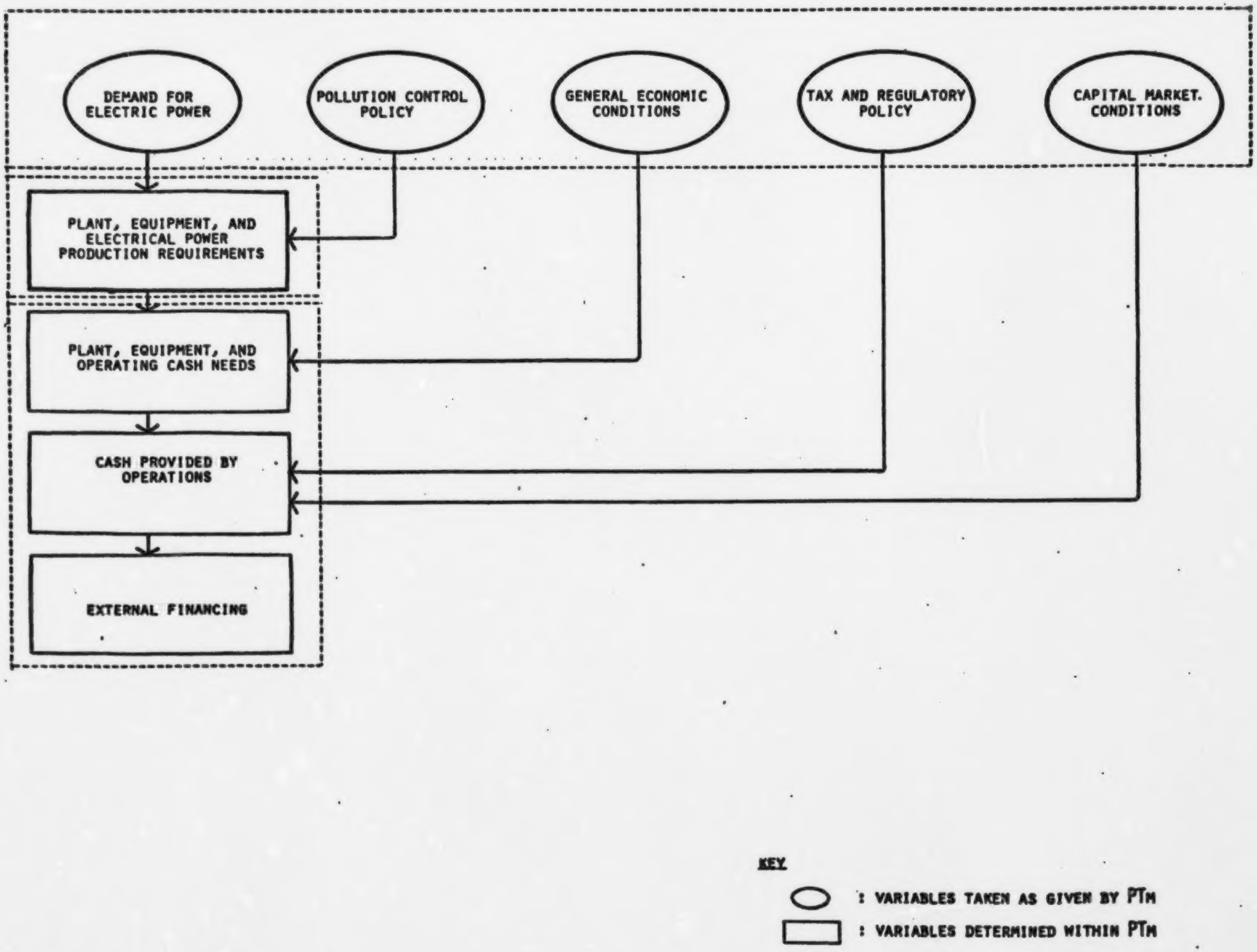

DEMAND FOR ELECTRIC POWER
POLLUTION CONTROL POLICY
GENERAL ECONOMIC CONDITIONS
TAX AND REGULATORY POLICY
CAPITAL MARKET. CONDITIONS
PLANT, EQUIPMENT, AND ELECTRICAL POWER PRODUCTION REQUIREMENTS
PLANT, EQUIPMENT, AND OPERATING CASH NEEDS
CASH PROVIDED BY OPERATIONS
EXTERNAL FINANCING
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

Exhibit II-A-2

DETERMINANTS OF PLANT AND EQUIPMENT IN SERVICE
AND IN CONSTRUCTION FOR THE ELECTRIC UTILITY INDUSTRY

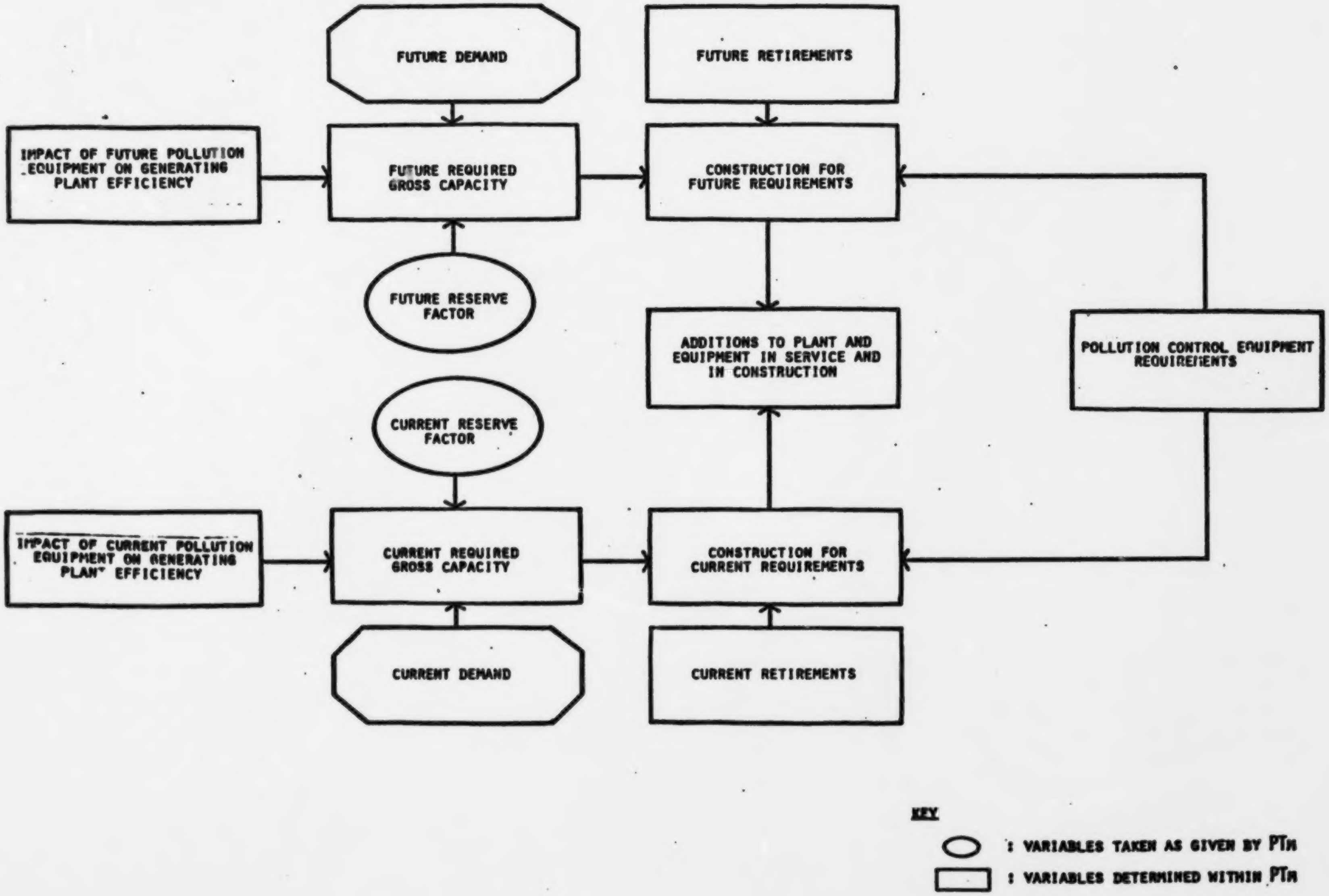

FUTURE DEMAND
FUTURE RETIREMENTS
IMPACT OF FUTURE POLLUTION EQUIPMENT ON GENERATING PLANT EFFICIENCY
FUTURE REQUIRED GROSS CAPACITY
CONSTRUCTION FOR FUTURE REQUIREMENTS
FUTURE RESERVE FACTOR
ADDITIONS TO PLANT AND EQUIPMENT IN SERVICE AND IN CONSTRUCTION
POLLUTION CONTROL EQUIPMENT REQUIREMENTS
CURRENT RESERVE FACTOR
IMPACT OF CURRENT POLLUTION EQUIPMENT ON GENERATING PLANT EFFICIENCY
CURRENT REQUIRED GROSS CAPACITY
CONSTRUCTION FOR CURRENT REQUIREMENTS
CURRENT DEMAND
CURRENT RETIREMENTS
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

Exhibit II-A-3

DETERMINANTS OF USES OF FUNDS
FOR THE ELECTRIC UTILITY INDUSTRY

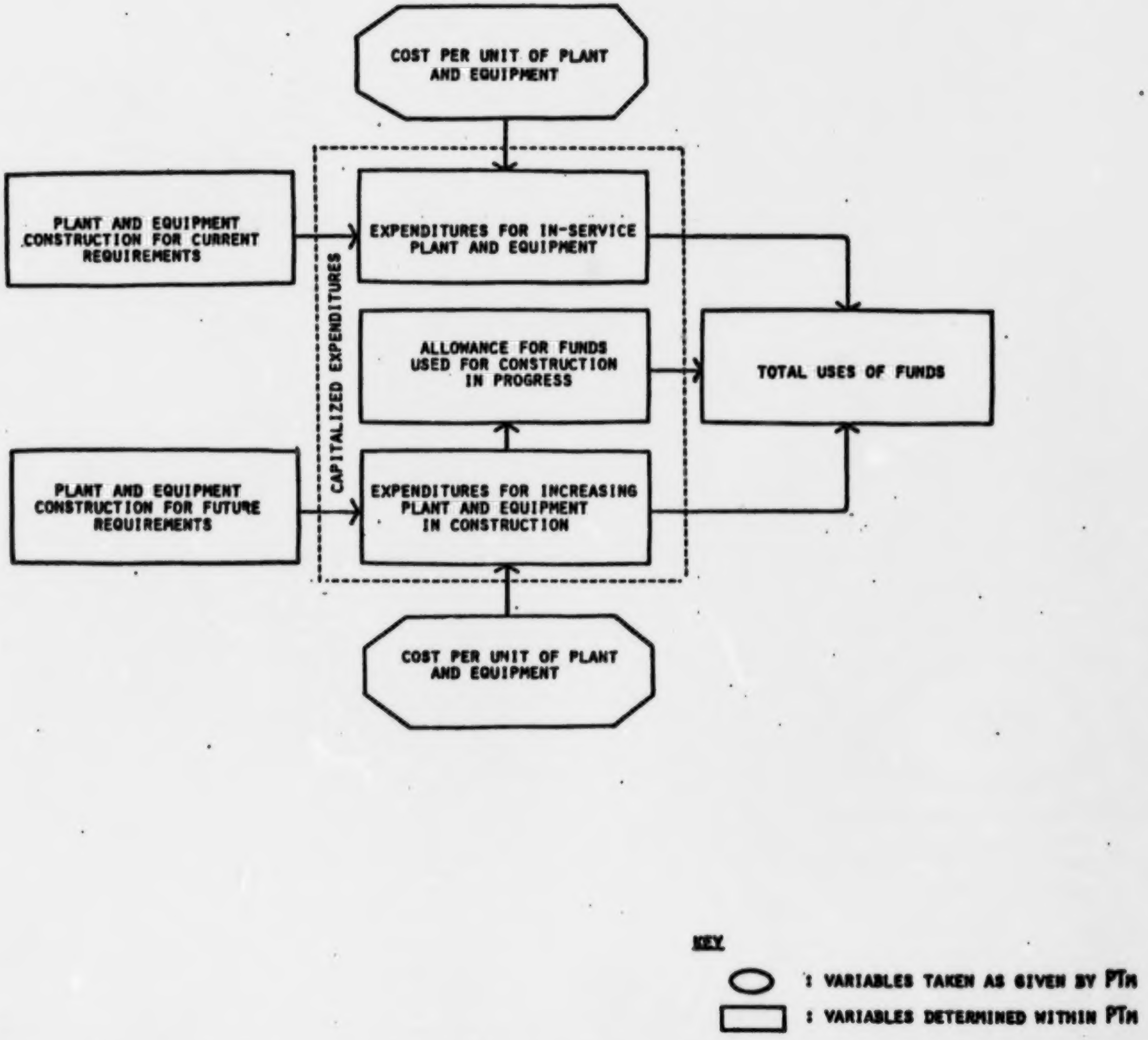

COST PER UNIT OF PLANT AND EQUIPMENT
PLANT AND EQUIPMENT CONSTRUCTION FOR CURRENT REQUIREMENTS
EXPENDITURES FOR IN-SERVICE PLANT AND EQUIPMENT
CAPITALIZED EXPENDITURES
ALLOWANCE FOR FUNDS USED FOR CONSTRUCTION IN PROGRESS
TOTAL USES OF FUNDS
PLANT AND EQUIPMENT CONSTRUCTION FOR FUTURE REQUIREMENTS
EXPENDITURES FOR INCREASING PLANT AND EQUIPMENT IN CONSTRUCTION
COST PER UNIT OF PLANT AND EQUIPMENT
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

Exhibit II-A-4

DETERMINANTS AND COMPOSITION OF TOTAL SOURCES OF FUNDS FOR THE ELECTRIC UTILITY INDUSTRY

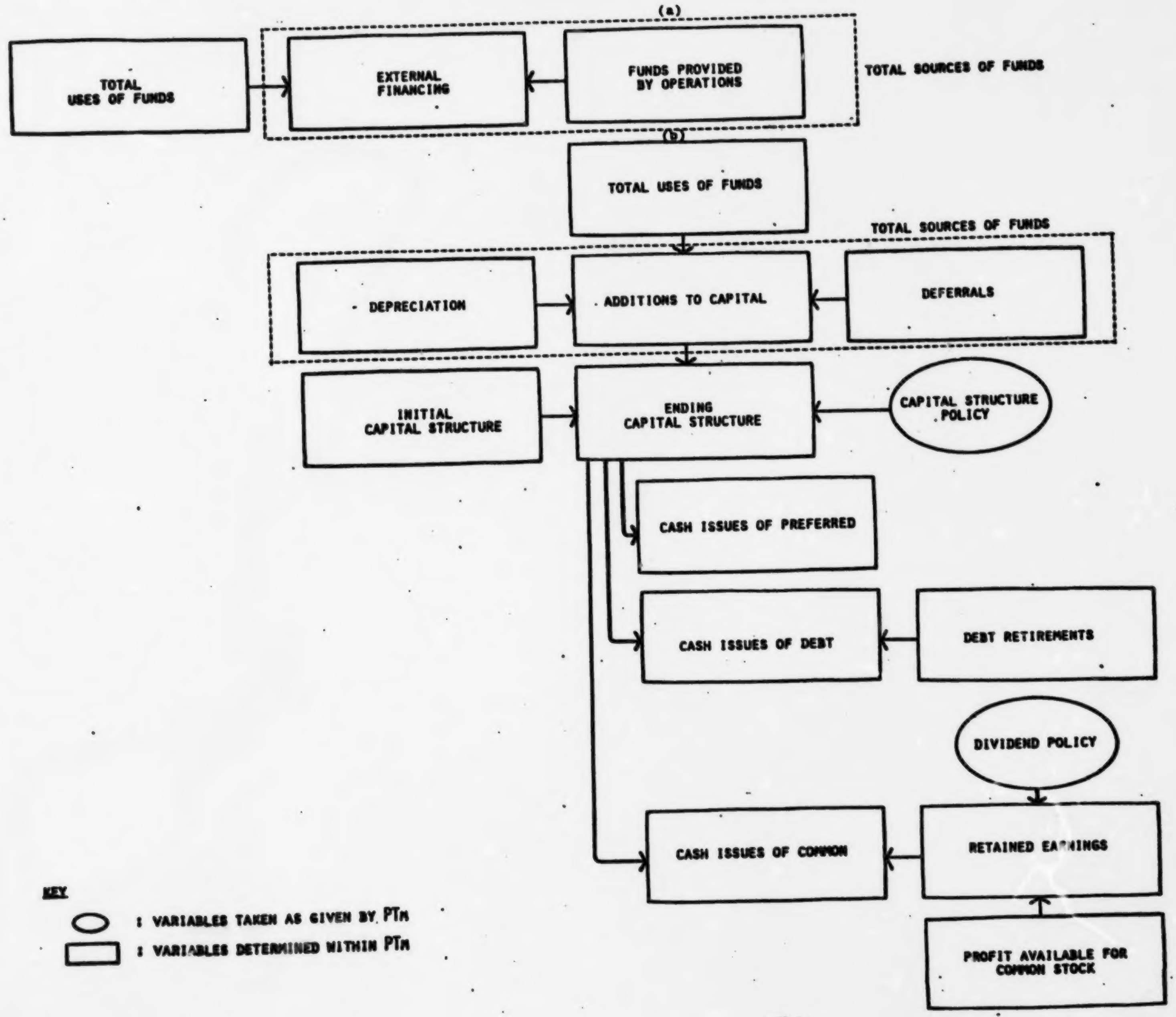
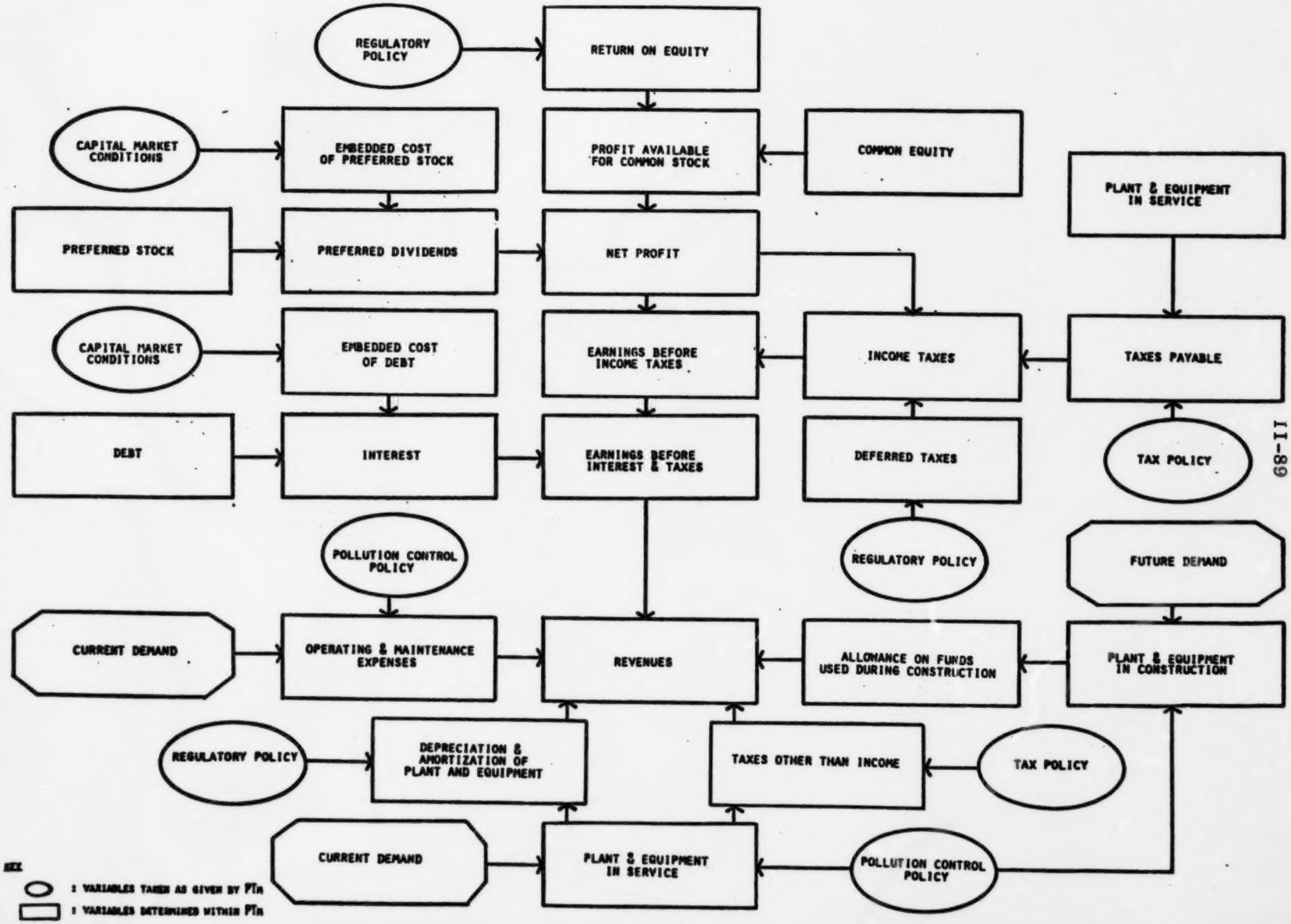

(a)
TOTAL USES OF FUNDS
EXTERNAL FINANCING
FUNDS PROVIDED BY OPERATIONS
TOTAL SOURCES OF FUNDS
(b)
TOTAL USES OF FUNDS
TOTAL SOURCES OF FUNDS
DEPRECIATION
ADDITIONS TO CAPITAL
DEFERRALS
INITIAL CAPITAL STRUCTURE
ENDING CAPITAL STRUCTURE
CAPITAL STRUCTURE POLICY
CASH ISSUES OF PREFERRED
CASH ISSUES OF DEBT
DEBT RETIREMENTS
DIVIDEND POLICY
CASH ISSUES OF COMMON
RETAINED EARNINGS
PROFIT AVAILABLE FOR COMMON STOCK
KEY
: VARIABLES TAKEN AS GIVEN BY PTM
: VARIABLES DETERMINED WITHIN PTM

Exhibit II-A-5

DETERMINANTS OF REVENUES, EXPENSES, AND PROFITS FOR THE ELECTRIC UTILITY INDUSTRY


REGULATORY POLICY
RETURN ON EQUITY
CAPITAL MARKET CONDITIONS
EMBEDDED COST OF PREFERRED STOCK
PROFIT AVAILABLE FOR COMMON STOCK
COMMON EQUITY
PLANT & EQUIPMENT IN SERVICE
PREFERRED STOCK
PREFERRED DIVIDENDS
NET PROFIT
CAPITAL MARKET CONDITIONS
EMBEDDED COST OF DEBT
EARNINGS BEFORE INCOME TAXES
INCOME TAXES
TAXES PAYABLE
DEBT
INTEREST
EARNINGS BEFORE INTEREST & TAXES
DEFERRED TAXES
TAX POLICY
POLLUTION CONTROL POLICY
REGULATORY POLICY
FUTURE DEMAND
CURRENT DEMAND
OPERATING & MAINTENANCE EXPENSES
REVENUES
ALLOWANCE ON FUNDS USED DURING CONSTRUCTION
PLANT & EQUIPMENT IN CONSTRUCTION
REGULATORY POLICY
DEPRECIATION & AMORTIZATION OF PLANT AND EQUIPMENT
TAXES OTHER THAN INCOME
TAX POLICY
CURRENT DEMAND
PLANT & EQUIPMENT IN SERVICE
POLLUTION CONTROL POLICY
KEY
: VARIABLES TAKEN AS GIVEN BY PIM
: VARIABLES DETERMINED WITHIN PIM

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

VOLUME III

NATIONAL FINANCIAL IMPACTS

MAY 1976

VOLUME III

TABLE OF CONTENTS

		Page
List of Exhibits		(III-iii)
Chapter		
1	INTRODUCTION AND CONCLUSIONS	III-1
2	HISTORY OF THE REGULATIONS AND AMOUNT OF CAPACITY AFFECTED	III-4
	History of the Clean Air Act Regulations	III-4
	History of Federal Water Pollution Control Regulations	III-7
	Capacity Impacted by Federal Air and Water Regulations	III-8
3	CAPITAL EXPENDITURES IMPACTS OF AIR AND WATER REGULATIONS	III-20
	Capital Expenditures by Regulation	III-20
	Timing of Capital Expenditure Requirements	III-22
	Capital Expenditures by Type of Pollution Control Equipment	III-23
	Capital Expenditures to Make Up Capacity Losses	III-26
	Other Air Regulations	III-28
4	OTHER FINANCIAL AND ENERGY IMPACTS	III-32
	External Financing Requirements	III-32
	Operation and Maintenance Costs	III-34
	Operating Revenues and Consumer Charges Impacts	III-35
	Impact on the Average Residential Bill for Electricity	III-36
	Energy Impacts	III-39

Chapter		Page
5	ASSUMPTIONS FOR ANALYSIS OF THE AIR REGULATIONS	III-42
	Capacity Affected by the Regulations	III-43
	Capital Costs	III-48
	Operation and Maintenance Costs	III-50
	Capacity Loss/Energy Penalty	III-51
	Financing	III-52
6	ASSUMPTIONS FOR ANALYSIS OF WATER REGULATIONS	III-53
	Capacity Affected	III-55
	Capital and Operation and Maintenance Cost Estimates	III-65
7	COMPARISON OF CURRENT ANALYSIS OF WATER REGULATIONS AND DECEMBER 1974 RESULTS	III-70

VOLUME III

LIST OF EXHIBITS

Exhibit	
III-1	Financial Impacts of Air and Water Pollution Controls for Economic and Non-Federal Reasons, For Selected Years
III-2	Financial Impacts of Compliance with the Clean Air Act and Federal Water Pollution Control Act After 316(a) Exemptions, For Selected Years
III-3	Financial Impacts of Compliance with the Clean Air Act and Federal Water Pollution Control Act Before 316(a) Exemptions, For Selected Years
III-4	Capital Expenditures Impacts of Compliance With Clean Air Act
III-5	Capital Expenditures Impacts; Effluent Guidelines Pollution Control Equipment
III-6	Capital Costs Used in Clean Air Act Analysis
III-7	Operations and Maintenance Costs Used in Clean Air Act Analysis
III-8	Coverage Assumptions for Baseline Conditions For Coal Units in 1980 and 1985
III-9	Coverage Assumptions for Compliance with Clean Air Act For Coal Units in 1980 and 1985
III-10	Coverage Assumptions for Compliance with SCS 50 Percent Option For Coal Units in 1980 and 1985
III-11	Coverage Assumptions for Compliance with SCS 90 Percent Option For Coal Units in 1980 and 1985
III-12	1985 Coverage Assumptions for Water Effluent Guidelines (percent)
III-13	1985 Coverage Assumptions for Water Effluent Guidelines (kilowatts)
III-14	Capital Cost Growth--Thermal Guidelines

Exhibit

III-15 Annual Operating Cost Growth--Thermal Guidelines

III-16 Capital Cost Growth--1977 Chemical Guidelines

III-17 Capital Cost Growth--1983 Chemical Guidelines

III-18 Annual Operating Cost Growth--1977 Chemical Guidelines

III-19 Annual Operating Cost Growth--1983 Chemical Guidelines

III-20 Capital Cost Growth--Cooling Towers for Entrainment Guidelines

CHAPTER 1

INTRODUCTION AND CONCLUSIONS

This volume of the report presents the direct effects of federal pollution control regulations upon the electric utility industry. The air pollution control impacts are based primarily upon the results of EPA-sponsored research by three firms: (1) engineering cost studies of air pollution control equipment by PEDCO Environmental Specialists, Inc.;[1] (2) regional coal plant analyses to estimate compliance strategies, by Sobotka & Co., Inc.;[2] and (3) economic and financial evaluations by TBS based upon those cost and compliance estimates. The effluent guidelines impacts are based primarily upon EPA estimates of compliance levels and unit costs as the inputs to TBS' economic and financial evaluation.

CONCLUSIONS

The major financial conclusions presented in this volume are:

- Capital expenditures, net of the increase in construction work-in-progress, will increase by $14.5 billion during 1975-1980 and by $25.0 billion in 1975-1985 (1975 dollars).[3] Those impacts represent increases above the industry's level of baseline capital expenditures of 12.3 and 10.5 percent respectively.

---

[1] *PEDCO Environmental Specialists, Inc., Flue Gas Desulfurization, Process Cost Assessment (April 30, 1975), and Particulate and Sulfur Dioxide Emission Control Cost Study of the Electric Utility Industry (September 12, 1975).*

[2] *Sobotka & Co. Inc., unpublished analyses submitted to the Environmental Protection Agency, November 17, 1976.*

[3] *Unless otherwise noted, all dollar figures in this volume refer to 1975 dollars.*

- Those increases in capital expenditures will be spread over the entire eleven-year period, 1975-1985, with the annual figure ranging from $1.5 billion to $4.2 billion. Furthermore, even after 1985 the regulations will cause a continuing impact in capital expenditures of over $2.0 billion per year, primarily because all new coal plants will require pollution control equipment of some form.

- Scrubbers alone will account for half of the total capital expenditures impact ($12.8 of the $25.0 billion). Precipitators will account for another 25 percent and cooling towers will represent 16 percent.

- External financing to support these expenditures will increase in the six-year period, 1975-1980, by $14.5 billion, and in the 1975-1985 period by $21.9 billion. Those impacts represent increases above the industry's baseline level of external financing of 16.1 and 11.5 percent, respectively.

- Annual operating and maintenance expenses will increase 4.0 percent by 1980 and 6.0 percent by 1985. The annual increase by 1985 will be $3.2 billion.

- Operating revenues and average consumer charges will have to increase 5.4 percent by 1980 and 6.7 percent by 1985 to cover these costs. The 1985 increase will total $6.5 billion and come to 2.1 mills per kilowatt-hour sold.

- The average residential customer's monthly electric bill will increase as a result by approximately $1.80 in 1980 and $2.80 in 1985. In current dollars, that is, including the effects of inflation, the impact will be $2.40 per month in 1980 and $4.70 per month in 1985.

- The total direct and indirect impact upon residential customers, assuming that all non-residential customer impacts are eventually passed on to consumers in the form of increased product prices, will be approximately $4.00 per customer per month by 1980 and $5.80 by 1985.

- The energy consumption of the electric utility industry by 1985 will increase slightly to provide power to operate the pollution control equipment--by approximately 0.4 quads (quadrillion Btu) on a base of 33.2 quads.

These conclusions and the data and analysis supporting them are the substance of the following chapters. Chapter 2 provides a brief history of the legislation and summarizes the amount of capacity which will be affected by it through 1985. Chapter 3 then presents the capital expenditures impacts of the regulations. Chapter 4 follows with a presentation of all other financial and energy impacts of the regulations. The next two chapters document the assumptions used in the analysis pertaining to the air regulations (Chapter 5) and the water effluent guidelines (Chapter 6). Chapter 7 concludes with a comparison of the current analysis of the water effluent guidelines against the results published in December 1974.

CHAPTER 2

HISTORY OF THE REGULATIONS AND AMOUNT OF CAPACITY AFFECTED

This chapter presents a brief review of the regulations being analyzed and of the amount of generating capacity which they will affect.

HISTORY OF THE CLEAN AIR ACT REGULATIONS

In 1971, pursuant to the Clean Air Act of 1970, EPA promulgated primary national ambient air quality standards for six pollutants (sulfur dioxide, nitrogen oxides, hydrocarbons, carbon monoxide, and particulates) to protect public health. The electric utility industry was a principal source for two of these: sulfur dioxide and particulates.

In 1972, the states submitted State Implementation Plans (SIPs) which included constant emission limitations to insure the attainment and maintenance of the ambient air quality standards. Under the act, compliance was mandated for stationary sources by mid-1975, with extensions available through state initiatives up to mid-1977.

According to EPA's analyses of the original SIPs, the electric utility industry would be unable to comply within the statutory compliance dates; there simply would not be adequate availability of stack-gas scrubbers, other control technologies, and low-sulfur fuels. That shortage of complying control technologies and fuels came to be referred to as "the clean fuels deficit."

In response, EPA adopted a "Clean Fuels Policy" which urged the states to voluntarily relax sulfur dioxide regulations which were more stringent than necessary to protect public health. In addition, EPA embarked upon a policy of administratively extending compliance dates where primary standards are not endangered.

Recent events, however, have adversely affected the compliance outlook for the remainder of the decade. The oil embargo, subsequent energy policies to reduce imports, natural gas curtailments and the general financial situation of the utilities raised serious questions regarding existing policies to eliminate the clean fuels deficit.

Consequently, in November 1974, at the request of the Energy Resources Council (ERC), EPA headed an Interagency Task Force to analyze the implications of alternative sulfur dioxide policies. The results of that analysis were an ERC recommendation and the submission to Congress of an Administration-sponsored amendment to the Clean Air Act of 1970 which would:

- Permit existing isolated coal-fired power plants at which Supplementary Control Systems (SCS)[1] are reliable and enforceable to use SCS to meet ambient air quality standards and to delay until 1985 the installation of permanent controls (i.e., scrubbers or low sulfur coal);
- Require all other existing plants to install permanent controls as expeditiously as possible;

---

[1] *Supplementary Control Systems (SCS) achieve ambient air quality standards by switching power plants to low sulfur fuels or by reducing generation during periods in which meteorological conditions would otherwise cause violations of ground-level air quality standards.*

- Require all new plants to meet new source performance standards (NSPS) or state emission regulations where more stringent than NSPS.

That recommendation has not been acted upon by Congress at this writing.

In 1972, the Sierra Club and other environmental groups filed suit against EPA for failure to promulgate regulations under the Clean Air Act to prevent the significant deterioration of air quality. Both the District Court of the District of Columbia and the U.S. Court of Appeals for the District of Columbia Circuit granted the Sierra Club's motion and required EPA to promulgate significant deterioration regulations. In June 1973, the Supreme Court, by a four-to-four vote, affirmed the judgment of the Court of Appeals.

After extensive public participation and technical and economic analyses, EPA published Significant Deterioration Regulations in December 1974, which are based on allowable increments of pollutant concentrations for specific categories of new major industrial sources under an area classification procedure. Subsequently, the Administration, as part of the Energy Independence Act of 1975, requested Congress to consider legislation which would clarify Congressional intent on the prevention of significant deterioration of air quality. The Administration requested that Congress carefully examine the potential effects of a significant deterioration policy, including the consideration of its complete elimination as well as other alternative approaches. In addition, Congress was asked to provide explicit guidance that would allow a balancing of environmental, economic, and energy concerns in any legislative determination of the significant deterioration issue. Discussion and evaluation of several alternative policies are underway now in both the Senate and the House of Representatives.

The impacts presented in this volume which relate to air pollution control are those which result from the Clean Air Act of 1970. The volume also discusses briefly the projected effects of the SCS amendment if adopted. At this time, only brief estimates have been included of the impacts of the federal nonsignificant deterioration regulations and of the federal nitrogen oxide emission limitation.

HISTORY OF THE FEDERAL WATER POLLUTION CONTROL REGULATIONS

On March 4, 1974, EPA published a notice of proposed rule-making, announcing its intention to establish limitations on the discharge of pollutants into waterways by existing and new point sources within the electric utility industry. These proposed regulations were promulgated pursuant to the relevant sections of the Federal Water Pollution Control Act of 1972. With respect to thermal pollution, the proposed rule-making exempted all small units (defined by the Federal Power Commission as units in plants of 25 megawatts or less and in systems of 150 megawatts or less in total capacity), and all units which were scheduled for retirement prior to 1990.

Interested parties were invited to submit written comments on the proposed regulations, and EPA held public hearings in July to afford those who had submitted comments an opportunity to explain the substance of their position in detail. Based upon these written comments, public hearings, and subsequent interaction among interested parties, the guidelines were revised.

On October 8, 1974, EPA published in the Federal Register (39 FR 36186) final guidelines and standards for steam electric power generation. The final thermal guidelines exempt all units placed into service before 1970, and all but the largest baseload units (defined as units of 500 megawatts or greater) placed into service between January 1, 1970 and January 1, 1974. Thus, the final thermal guidelines differed from those proposed in March 1974 in terms of the proportion of existing steam electric units which were covered by the Act. In addition, the final chemical guidelines were modified from those previously proposed.

In December 1974, EPA published its economic analysis of the impact of the final effluent guidelines upon the electric utility industry (Economic Analysis of Effluent Guidelines, Steam Electric Powerplants). The impacts presented in this volume which relate to water pollution control regulations update that earlier analysis on the basis of more recent information regarding electricity sales growth, capacity additions, capital costs, and compliance of the industry.

CAPACITY IMPACTED BY FEDERAL AIR AND WATER REGULATIONS

The effect of these regulations will be to require pollution control equipment to be installed on a significant share of the electric utility industry's generating plants. EPA's final chemical effluent guidelines, for example, will affect approximately half of all fossil and nuclear powerplants in the U.S. by 1985. Those affected units will represent 40 percent of the industry's capacity at that time. The air regulations, on the other hand, will significantly impact only coal-fired plants. Again, however, that amounts to approximately 40 percent of the industry's capacity.

The purpose of this section is to provide an overview of the magnitude and types of those impacts. Later chapters (5 and 6) present EPA's detailed estimates, regulation by regulation.[4] This section also presents the data from a complementary point of view: it is summarized and presented by type of capacity affected rather than simply by regulation.

There are at least five different compliance problems which are dealt with in this chapter. Three relate to the water effluent guidelines: thermal pollution, entrainment of organisms in the cooling water, and chemical pollution. There are two more relating to the air regulations: sulfur dioxide emissions (SO_2), and total suspended particulate emissions (TSP).

In some cases state and local regulations and even economic reasons can and do force utilities to install pollution control equipment regardless of the presence or absence of federal regulations. The most significant example of this is the installation of cooling towers and the use of closed-cycle cooling systems either to comply with State Water Quality

---

[4] *The estimates of the capacity affected which are used in this report were developed by or for EPA; the capacity which falls under the purview of the water effluent guidelines was estimated by EPA regional personnel, and that which is affected by the air regulations was furnished by Sobotka Associates.*

Standards or because of the unavailability of adequate cooling water at a plant site. These reasons are expected to account for approximately 40 percent of all the cooling towers to be installed in the 1975-1985 period. The federal regulations therefore will be the cause of cooling tower construction in only the other 60 percent of the installations.

The one other pollution area in which local and state regulations and economic reasons are significant is in the installation of precipitators to collect particulate emissions from flue gases. Virtually all coal plants are now equipped or built with some type of precipitator which in certain instances will meet the federal standards and in other instances will require upgrading in efficiency.

The exemption provision in Section 316(a) of the Federal Water Pollution Control Act is a final significant factor to recognize in considering the number of plants affected by EPA's regulations. That provision allows for exemptions from the thermal regulations if the effluent discharges would not harm marine life in the receiving body of water. Based upon reports from EPA regional personnel, such exemptions could exceed 50 percent of the original number of plants affected. Some of those exempted units are included in those eventually covered by the State Water Quality Standards. The later chapters report the extent of these exemptions in some detail, but this chapter deals only with estimates of the final impacts after exemptions.

The sections below describe briefly the magnitude of the capacity affected by the regulations in separate sections for each type of capacity: nuclear, coal, oil, and gas. The discussion is in terms of impacts by 1985 when all retrofitted units will be in place and when the pollution control equipment on new sources through 1985 will also be in service.

Nuclear Plants Impacted By Effluent Guidelines

The projections presented in Volume II show nuclear capacity increasing from 8 percent of the industry's total capacity in 1975 to almost 18 percent in 1985. By the end of 1985 132,000 megawatts of nuclear capacity are projected to be in service. Its share of total generation will be even higher because the potential capacity factors for individual nuclear plants can be well above 70 percent. Many of these units are projected by EPA to be required to install pollution control equipment in order to comply with the federal effluent guidelines. The impact in each of the three areas of regulation are described briefly below.

First, EPA's final chemical guidelines will require new expenditures on approximately 52.5 million kw, or 40 percent of the nuclear capacity in service. As the table on p. III-12 shows, 70 percent of the nuclear units already in-service before 1974 will be required to be retrofitted (i.e., fitted onto units which are already in operation at that time) with additional equipment in order to meet the chemical guidelines. Approximately one-third of the new nuclear units placed into service in 1974 or later will be required to add such equipment during design in order to be in compliance when the units become operational.

NUCLEAR UNITS
Impact of EPA Effluent Guidelines
(million kw)

	Pre-1974 units	1974-1978 units	1979-1985 units	Total 1985 Capacity
Nuclear Capacity	21.1	40.6	70.3	132.0
Impacted by Water Guidelines				
Chemical	14.8	13.8	23.9	52.5
Thermal (after 316(a)*	4.6	10.1	17.6	32.3
Entrainment	3.0	1.5	-	4.5

---

*net of coverage for Economic Reasons

Source: EPA, Exhibits III-12 - III-13

The capacity affected by the thermal effluent guidelines is less extensive than for the chemical guidelines. Many plants are expected to be granted exemptions under Section 316(a) of the Federal Water Pollution Control Act by demonstrating that regulations are more stringent than necessary. After excluding those plants with exemptions, 32.3 million kilowatts or approximately 24 percent of the nuclear plants in service in 1985 will be required to utilize closed-cycle cooling systems to meet the federal guidelines. The regulations will require closed-cycle cooling for 22 to 25 percent of the nuclear units in service regardless of the plant's age. Approximately an equal number of nuclear units will be utilizing closed-cycle cooling for economic reasons and State Water Quality Standards. The remaining units are not expected to pose an environmental hazard in terms of the thermal effluent guidelines.

Some additional cooling towers will be required by federal entrainment regulations under Section 316(b) of the Clean Water Act. Some nuclear plants will have to use closed-cycle cooling to prevent the intake and entrainment of certain organisms along with cooling water. Overall, an additional 4.5 million kilowatts will require cooling towers to comply with the entrainment guidelines. New plants, however, are expected to meet the guidelines through simple design changes at no increase in plant or operating costs.

Coal Plants Impacted By Effluent Guidelines

Coal plants are the only type significantly affected by both air and water federal regulations. Nuclear plants are impacted by water regulations but result in no SO_2 or particulate emissions. Oil and gas plants are also impacted by the water regulations, but gas units produce no air pollution subject to the federal regulations and oil units can generally comply with the regulations simply by burning lower sulfur oil at a slight price penalty.[3]

Coal-burning plants accounted for almost 40 percent of the industry's total capacity at the end of 1974. The projections presented in Volume II indicate that coal units will increase to approximately 46 percent of total capacity by 1985 by increasing in absolute numbers from 186 million kilowatts in 1974 to 333 million in 1985. Because the coal units are primarily baseload and cycling units, coal's share of total generation by the industry is and will continue to be slightly higher, ranging from 45 to 51 percent during the eleven-year period.

---

[3] *Projected by EPA to be 0.75 to 0.80 mills per kwh in 1975 dollars.*

EPA's regional personnel estimated impacts of the effluent guidelines upon fossil capacity in total, without singling out coal units. Assuming impacts proportional to the coal share of fossil capacity, the estimates below have been derived for each of the three areas of effluent guidelines.

First, EPA's chemical guidelines will require additional equipment and expenditures at slightly over half of all coal plants by 1985. That ratio is expected to be relatively constant for plants built before 1974, those to be completed between 1974 and 1978, and those built after 1978.

Second, in terms of the thermal guidelines only 69.7 million kw or just over 20 percent of the capacity is anticipated to require cooling towers and closed-cycle cooling systems in order to comply with the federal guidelines. In terms of age of unit, under 10 percent of the pre-1974 units were expected to install closed-cycle cooling for compliance with the federal guideline, while just over one-third of the new units built after that are projected to do so. The expected level of installation of cooling towers to meet State Water Quality Standards is low (about 5 percent), but in combination with those installed for economic reasons, will be roughly equal to the federal requirement.

Third, the federal regulations covering entrainment, Section 316(b), will require closed-cycle cooling at approximately 3.4 million additional kw by 1985. Units completed in 1979 and later years are expected to be designed to meet the regulations at no increment in capital or operating cost.

COAL UNITS
Impact of EPA Effluent Guidelines by 1985
(million kw)

	Pre-1974 units[a]	1974-1976 units	1977-1985 units[b]	Total 1985 Capacity
Coal Capacity	173.5	29.7	129.7	332.9
Impact of Guidelines				
Chemical	105.8	16.6	72.6	195.0
Thermal (after 316(a))	13.9	10.4	45.4	69.7
Entrainment	2.4	1.0	-	3.4

---

[a] *Excludes 23.1 million kw expected to be retired by 1985, and includes 11.1 million kw converted from oil to coal under FEA conversion orders and 9.2 million kw converted from gas to coal for economic reasons.*

[b] *This time period chosen in preference to the 1979 and later period used in the earlier Effluent Guidelines report for consistency within the present analysis*

Source: EPA, Exhibits III-12, III-13

Coal Plants Impacted By Air Regulations

Under the Clean Air Act of 1970, EPA has published ambient air quality standards for sulfur dioxide (SO_2), total suspended particulate (TSP) and nitrogen oxide (NOX) emission levels. States have established State Implementation Plans (SIPs) for achieving those levels on a state-by-state basis. Each electric utility company, however, also has a choise of alternative methods of compliance. The selection of a compliance technology for SO_2 is generally the most significant of the three. First, its cost is usually much higher than the costs of meeting the other regulations. Second, its selection often dictates the mode of compliance of the others--for example, the use of Western low-sulfur coal to meet SO_2 levels required that money be spent to upgrade the units' precipitator.

EPA has developed projections of the amount of coal capacity which will be impacted by the regulations. Furthermore, its contractor, Sobotka Associates, has also estimated the utilization levels of the various control strategies by 1985. The sections below summarize the degree of impact expected and the major controls which are anticipated. The three major compliance strategies expected to be used for SO_2 for example are:

- Install and operate scrubbers (flue gas desulfurization).
- Burn Eastern and Western coal.
- Utilize washing and blending of coals with different sulfur characteristics.

It was estimated that 224.5 million kw or approximately 67 percent of the 1985 coal capacity would require controls to meet the federal SO_2 regulations and would therefore need to adopt one of the compliance options. The table on p. III-17 summarizes the expected breakdown of the three compliance options for those units.

COAL UNITS

SO_2 COMPLIANCE METHODS BY 1985

(million kw)

	Pre-1974 units*	1974-1976 units	1977-1985 units	Total 1985 Capacity
Coal Capacity	173.5	29.7	129.7	332.9
SO_2 Compliance Method				
- Scrubbers	42.9	11.5	63.5	117.9
- Low Sulfur Coal	1.4	2.2	66.2	69.8
- Medium Sulfur Coal	21.8	11.4	-	33.2
- Washing/Blending	37.2	-	-	37.2
Total Requiring Controls	103.3	25.1	129.7	258.1
No Additional Controls Needed	70.2	4.6	-	74.9

---

*Excludes 33.1 million kw expected to be retired by 1985, and includes 11.1 million kw converted from oil to coal under EA conversion orders and 9.8 million kw converted from gas to coal for economic reasons.

Source: Sobotka & Co., Inc., Exhibit III-9

Scrubbers, it is expected, will be installed on 117.9 million kw by 1985, just over half of all the units which require controls and just over one-third of all 1985 coal capacity. Low-sulfur coal would be used by just over one-fifth of all coal plants in 1985. Washing or blending will be feasible only at plants which are very close to complying with the regulations now; about 37.2 million kilowatts will be using this strategy.

To comply with federal particulate regulations, there are essentially two alternatives for a coal-burning utility: either (1) install or upgrade an electrostatic precipitator unit, or (2) in combination with a scrubber, install a particulate scrubber to accomplish both SO_2 and particulate removal.

The selection of compliance technologies for the SO_2 and particulate regulations are very interdependent as mentioned. The table on page III-18 summarizes the share expected for each option for compliance with the particulate regulations. It was estimated by EPA that 261.8 million kw or 78.6 percent of the 1985 coal capacity would require one of the available compliance technologies. Precipitators are expected on almost exactly 50 percent of 1985 coal capacity while particulate scrubbers are projected to be used on the remaining 28 percent.

COAL UNITS
PARTICULATE COMPLIANCE METHODS BY 1985
(million kw)

	Pre-1974 units*	1974-1976 units	1977-1985 units	Total 1985 Capacity
Coal Capacity (million kw)	173.5	29.7	129.7	332.9
Particulate Compliance Method				
- Precipitators	81.3	18.2	66.2	165.7
- Particulate Scrubbers	21.1	11.5	63.5	96.1
Total kw requiring controls	102.4	29.7	129.7	261.8

Excludes 23.1 million kw expected to be retired by 1985, and includes 11.1 million kw converted from oil to coal under FEA conversion orders and 9.2 million kw converted from gas to coal for economic reasons.

Source: EPA, Exhibit III-9

Control strategies and costs for NOX control have been difficult to specify. Many plants are expecetd to make boiler modifications at a cost of approximately $3 per kw to permit two-stage combustion or off-stoichiometric firing to bring NOX emissions into compliance. Other new plants are expected to incorporate design features to accomplish the same objective. At this time no definitive projections are available for incorporation into the impact analysis.

Oil and Gas Units

Oil- and gas-burning electric generating plants are not affected extensively by federal pollution control regulations for three reasons:

- First, the water regulations affect primarily new units placed in service in 1974 and later years, a period during which the construction of oil and gas units is projected to drop sharply and cease altogether by 1978 in the case of gas and by 1981 in the case of oil;
- Second, the SO_2 regulations cover emissions which gas units do not produce and which oil units can curtail simply by burning low-sulfur oil at a fuel price premium of about fifty cents per barrel with no capital outlays whatsoever;
- Third, the particulate regulations cover emissions which are not generally produced at the specified levels by oil or gas units.

The chemical regulations cover virtually every steam electric plant in service in 1983 or later, as described above. For gas-fired units, however, approximately half of the current capacity is expected to be either converted to other fuels or retired by 1980 as a result of natural gas curtailments.

The thermal regulations (after accounting for exemptions under Section 316(a) of the Act) will require conversions to closed-cycle cooling on approximately 8 percent of oil capacity and 2 percent of gas capacity by 1985. Entrainment regulations, Section 316(b) of the Act, are projected to cover approximately 2 percent of both oil and gas capacity by that year.

CHAPTER 3

CAPITAL EXPENDITURES IMPACTS OF AIR AND WATER REGULATIONS

Perhaps the most widely accepted measure of the effect of pollution control regulations upon the electric utility industry is that of capital expenditures requirements.[1] That figure provides: (1) an indication of the total financing impact (from both external and internal sources); (2) a relative indication of the significance of the requirements as compared to the baseline projections; and (3) a meaningful yardstick with which to evaluate potential changes in the regulations and allowable technologies.

This chapter provides a full discussion of the capital expenditures impacts. The next chapter discusses the financial and energy impacts of pollution control. A separate volume, Volume IV, will deal with the ability of the electric utility industry to finance the required capital expenditures in view of current and projected capital market conditions.

CAPITAL EXPENDITURES BY REGULATION

The table below summarizes the capital expenditures impacts associated with each regulation. On a national basis the combined air and water regulations will require approximately 25.0 billion (1975 dollars)[2] of capital expenditures during 1975-1985 in addition to the planned expenditures of the industry of approximately 237.1 billion. Since much of the retrofitted equipment for existing plants will be installed by 1980, the 12.3 percent increase in capital expenditures from 1975 to 1980 is slightly higher than the longer term impact of 10.5 percent from 1975 to 1985.

---

[1] *In this discussion "capital expenditures" refer to the cash expenditures associated with units put into service; capital expenditures excludes changes in construction work in progress and allowances for funds used during construction.*

[2] *Unless specifically noted all dollar figures in this chapter will be expressed in constant 1975 dollars. 1975 dollars are assumed to include 9.5 percent inflation during 1975.*

CAPITAL EXPENDITURES IMPACTS
AIR AND WATER REGULATIONS TO 1980 AND 1985
(billion 1975 dollars)

	1975-1980	1975-1985
Baseline Capital Expenditures	118.3	237.1
Water Regulations		
- Chemical	+$ 0.6	+$ 0.9
- Thermal*	+ 0.3	+ 3.5
- Entrainment	+ 0.0	+ 0.5
Subtotal	+$ 0.9	+$ 5.0
Air Regulations		
-SO_2	+$ 8.6	+$ 11.6
-Particulate	+ 5.0	+ 8.4
Subtotal	+$ 13.6	+$ 20.0
TOTAL IMPACT	+$ 14.5	+$ 25.0

After consideration of exemptions under Section 316(a) of the Clean Water Act

Source: Exhibits III-4 and III-5

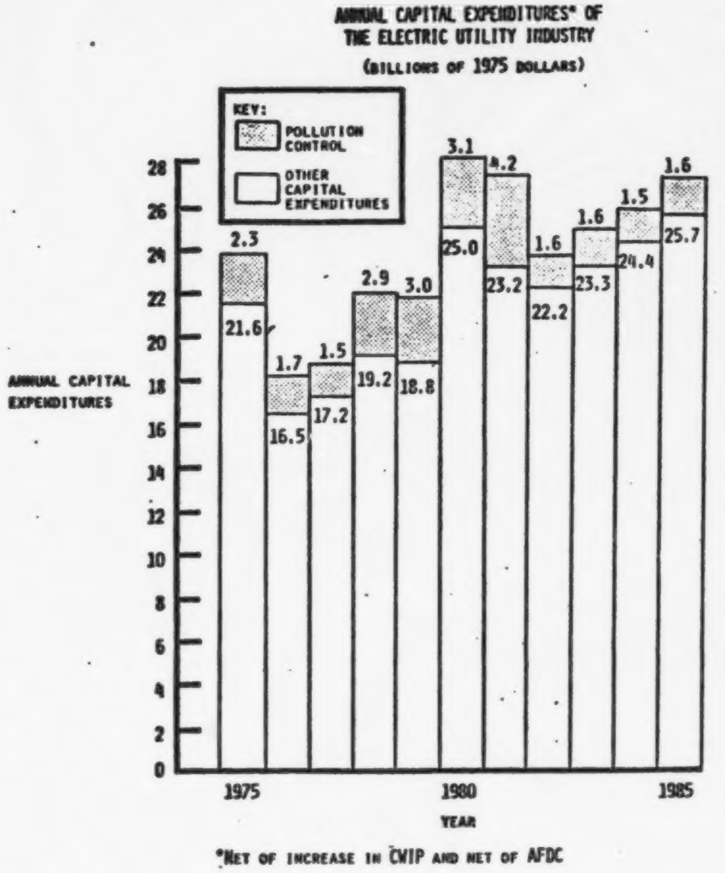
The air regulations require by far the largest capital outlays. Through 1980, they account for 94 percent of the total for pollution control, largely due to the time phasing of the water guidelines which require equipment in place generally in 1981 and 1982. Over the entire eleven-year period, moreover, the air regulations account for 80 percent of the impact. The reasons are the widespread coverage of the air regulations, affecting over two-thirds of the nation's coal units, and the relatively high cost of that pollution control equipment compared to water pollution control equipment.

The two major categories of air pollution regulations each account for significant capital expenditure requirements. The SO_2 regulations will cause an increase of $11.6 billion during 1975-1985, approximately 45 percent of the total effect in that period. The particulate regulations rank a close second to SO_2. Particulate regulations will require an increase of approximately $8.4 billion by 1985, which represents 35 percent of the total impact. The next largest regulation category is far smaller. It is thermal regulations at a level of $3.6 billion during 1975-1985.

TIMING OF CAPITAL EXPENDITURE REQUIREMENTS

The time phasing of the air regulations requires that most of the pollution control equipment needed in the next decade be installed before 1981. The only air pollution control equipment which will be installed after 1980 will be that required for new generating units as they come into service. The water pollution control equipment is generally expected to come into service in the 1981-1983 period. The resulting impact on capital expenditures in the short run is depicted in the chart below.

During the next six years, 1975-1980, the annual increase in capital expenditures for equipment placed into service will range from $1.5 to $3.1 billion per year. As the chart shows, the baseline capital expenditures before the pollution control impact in 1975-1980 are projected to range from $16.5 to $25.0 billion per year. The impact of the regulations during that period represents an increase ranging from 9 to 16 percent of the baseline projections and averaging 12 percent per year.



During the next five-year period, the first year, 1981, has the highest annual capital expenditures impact of the regulations of the full 1975-1985 perioc - $4.2 billion dollars (1975 dollars) of pollution control equipment coming into service in that single year. The other four years, 1982-1985, all show a lower level of capital expenditures impact of $1.5 to $1.6 billion per year. That impact represents a continuing expenditure level associated with new generating units as they come into service. That impact is approximately a 6 percent annual increase in plant placed into service from 1982 on.

CAPITAL EXPENDITURES BY TYPE OF POLLUTION CONTROL EQUIPMENT

Pollution control equipment varies substantially in cost. The range of unit costs is as broad as the range of impacts of individual regulations. In fact, the most widespread costs, chemical effluent costs, are also the lowest on a unit basis, being at or below $2 per kilowatt, as is shown in the table below. Cooling tower costs, the table also shows, can reach as much as $24 per kilowatt for retrofitted units. However, that is still far below the capital costs of precipitators for retrofitted units at $45 per kilowatt and scrubbers at $70 per kilowatt. The range for new units is even wider, from a capital cost of less than $6 per kilowatt for the most expensive water treatments to as high as $55 per kilowatt for the new coal plants which install scrubbers.

Unfortunately, for most utilities, there is not a free choice among the range of costs in order to meet a standard. The plant and control problem generally limits the choice to one or two. For example, if one builds a new coal plant then one must either install a scrubber or burn low sulfur coal--both incurring a considerable cost.

COMPARATIVE CAPITAL COSTS
FOR SELECTED POLLUTION CONTROL EQUIPMENT
(1975 dollars per kw)

	Retrofitted Units	New Units
Water		
Chemical Effluent Treatment (Fossil)[a]	$ 2.01	$ 1.52
Mechanical Cooling Tower (Fossil)[b]	24.09	5.77
Entrainment Screens (Fossil)[b]	1.93	4.08
Air		
Scrubber (SO_2 only)	70.27	55.50
Scrubber (with Venturi Scrubber)	86.83	72.06
Low Sulfur Coal (Western)	62.40	65.88
Washing/Blending	5.40	--
Precipitator	45.50	56.00

---

[a] *Costs for nuclear units lower than those shown*

[b] *Costs for nuclear units slightly higher for retrofitted units, lower for new units*

Source: Equipment for Air Treatment: Pedco Environmental Services, Equipment for Effluent Treatment: EPA, December, 1974 report.

The total capital expenditures impacts of each major category of control equipment is shown in the table below. The most widespread coverage, to meet chemical guidelines, encompasses almost 60 percent of all fossil steam and nuclear plants--some 355.6 million kw. Even at that coverage level, though, the total capital expenditure impact associated with chemical regulations is only $0.9 billion (1975 dollars) during the 1975-1985 period.

CAPITAL EXPENDITURES 1975-1985 BY TYPE OF POLLUTION CONTROL EQUIPMENT

(excluding equipment built for reasons other than compliance with federal regulations)

	Amount Built (million kw)	Capital Expenditures (billion 1975 dollars)
Water Regulations		
Chemical Treatment	355.6	$ 0.9
Cooling Towers*	136.3	4.1
Air Regulations		
Scrubbers[1]	117.9	12.8
Precipitators[2]	139.5	5.9
Boiler Modifications	69.9	1.3
TOTAL		$25.0

**For Thermal and Entrainment Guidelines*

[1] *12.8 billion includes $3.0 billion for particulate portion of combination scrubbers*

[2] *Includes both new precipitators and upgrading of mechanical precipitators*

Source: Exhibits III-4, III-5, III-9 and III-13

On the other hand, the expensive forms of pollution control will also be applied to a significant amount of capacity under the regulations. Scrubbers, for example, will be installed on approximately 117.9 million kilowatts of capacity through 1985, while Western low-sulfur coal will be burned at 139.5 million kilowatts.

The combination of such broad applications with high unit costs makes scrubbers and precipitators (largely used for Western low-sulfur coal) the dollar leaders in installations through 1985. Scrubbers will account for $12.8 billion, almost exactly half of the total air and water impact of $25.0 billion. Precipitators will cost another $5.9 billion in that period. The three most costly control categories, these two plus cooling towers, account for 91 percent of the total impact.

CAPITAL EXPENDITURES TO MAKE UP CAPACITY LOSSES

Scrubbers, precipitators, cooling towers, and Western low-sulfur coal have impacts on the effective capacity of the generating plants which utilize them. The first three require electricity for operation and thereby reduce the plant's net output capability. The fourth reduces output because the average Btu content of Western low-sulfur coals is much lower than the average coals now burned. In the short run such losses may be made up through the use of purchased power and increased utilization of peakers. In the long run, however, additional baseload or cycling capacity must be built to make up the losses.

The capital expenditures required to make up capacity losses which result from the federal pollution control regulations are summarized in the table below. Approximately 16 percent of the total capital expenditures required for pollution control in 1975-1985 are for this purpose. The total cost for making up capacity losses will be approximately $1.8 billion during 1975-1980 and $4.0 billion in the 1975-1985 period.

Scrubbers account for the largest cost in this area, requiring makeup additions at a total cost of $1.4 billion through 1980 and $2.1 billion through 1985. Cooling towers on nuclear and fossil steam plants are almost as expensive over the full eleven-year period, at $1.7 billion. Low-sulfur coal, while discussed a great deal, results in a relatively small requirement--only $0.1 billion. There are two reasons for that small impact: First, new plants built after 1976 which will burn Western low-sulfur coal are assumed to incorporate design changes which reduce the capacity loss to zero; and second, very few pre-1976 units are expected to burn Western low-sulfur coal, in part because of the capacity loss of over 4 percent which would be incurred.

CAPACITY EXPENDITURES FOR MAKEUP OF CAPACITY LOSSES DUE TO POLLUTION CONTROL REGULATIONS

(billion 1975 dollars)

	1975-1980	1975-1985
Water Regulations		
Cooling Towers	$0.2	$1.7
Air Regulations		
Scrubbers	$1.4	$2.1
Low Sulfur Coal	0.1	0.1
Precipitators	0.1	0.1
TOTAL	$1.8	$4.0

Source: EPA, Pedco estimates of loss rates, PTm computation of costs.

OTHER AIR REGULATIONS

In addition to the impacts described above, capital expenditures also may be increased to cover the costs of compliance with other federal air emission regulations. There are at least three such regulations possible at present: (1) the nitrogen oxide emissions regulation, which has been promulgated and simply was not included in the analysis; (2) the significant deterioration regulations, which are the subject of active Congressional and Agency review; and (3) the proposed Amendments to the Clean Air Act to permit the use of Supplemental Control Systems (SCS). The potential impact of each is discussed briefly below.

NOX Regulations

All plants placed into service in 1977 or later will be required to comply with EPA's emission regulations for nitrogen oxide. The two available methods of compliance both require changes in boiler operation: one is to utilize two-stage combustion, and the other is to employ off-stoichiometric firing. In either case a capital cost will be incurred in the range of $3 per kilowatt for new coal units and $0.30 to $4.00 for new oil and gas units (1975 dollars). On the basis of the capacity additions projected in Volume II, the total impact of this regulation on capital expenditures for plant placed into service will be approximately $200 million to $250 million in 1975-1980 and $450 million to $500 million in 1975-1985 (1975 dollars).

Significant Deterioration Regulations

The significant deterioration regulations were also excluded from this analysis. That regulation is currently under examination and its ultimate form is uncertain. A recent report by EPA[3] presented a detailed financial evaluation of several of the proposals for legislative changes in the area. The impact upon capital expenditures with the use of 1000 foot stacks under EPA's current guidelines (Federal Register, December 5, 1974) will be approximately $0.2 billion in 1975-1990. The impacts of the Senate or House proposals with EPA's definition of "Best Available Control Technology" (BACT) would be in the range of $1.2 to $2.1 billion. That figure would increase, however, to the $11.2 to $11.6 billion range if the Senate and House definitions of BACT are adopted. At this time no more conclusive results are available.

SCS Proposal

As mentioned earlier in the volume, EPA and the Energy Resources Council recommended to Congress an amendment to the Clean Air Act which would permit the use of SCS in existing coal plants. The use of SCS would be permitted only on an interim basis, however, with permanent controls still required by 1985.

The two major options considered for SCS implementation are:

- SCS 50 percent, which would permit SCS for those electric utility plants which contribute 50 percent or more of the ambient concentration of SO_2 in their area;

---

[3] EPA, *"A Preliminary Analysis of the Economic Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration," February 5, 1976.*

- SCS 90 percent, which would permit SCS only for those plants which contribute 90 percent or more of the ambient concentration of SO_2 in their area.

In either of the SCS options were adopted, then fewer expensive scrubbers would be built during 1975-1980. Just as many would be built by 1985 as would be built under the Clean Air Act. During the interim period, however, the plants using SCS would merely delay their permanent compliance installation.

The capital expenditure impacts of the use of SCS would be to reduce expenditures in the short run in favor of slightly higher expenditures in the long run, when both SCS equipment and permanent controls equipment will have been financed.

SCS-50 is the most liberal SCS policy because it would enable the largest number of units to operate SCS systems. Under that policy option, capital expenditures in the 1975-1980 period would drop from the Clean Air Act level by $1.8 billion. That reduction would be the result of some plants utilizing less expensive controls by 1980 than if they had to install permanent controls by that time.

By 1985, however, the SCS-50 option would result in increased capital expenditures of $3.1 billion higher than the Clean Air Act level as the plants which had invested in SCS for the short term were required to install permanent controls.

The SCS-90 option is smaller but permits SCS at fewer plants than SCS-50. The 1975-1980 capital expenditures impact would be a reduction of $1.3 billion, and in the 1975-1985 period would result in an increase over the Clean Air Act level of $1.9 billion.

CHAPTER 4

OTHER FINANCIAL AND ENERGY IMPACTS

The economic impact of pollution control regulations extends beyond capital expenditures to every facet of the electric utility industry. This chapter briefly addresses the following additional areas of impact of federal pollution control regulations on the utilities:

- external financing needs
- operation and maintenance
- operating revenues and consumer charges
- the average residential bill for electricity
- a comparison of annual costs on coal and nuclear units
- capacity losses and energy penalties

EXTERNAL FINANCING REQUIREMENTS

The capital expenditures for pollution control equipment described above will require a significant amount of financing by the industry in the nation's debt and equity markets. The amount of such financing is described briefly in this section; the financing capability and specific techniques of the industry are the subject of a separate chapter later in this volume.

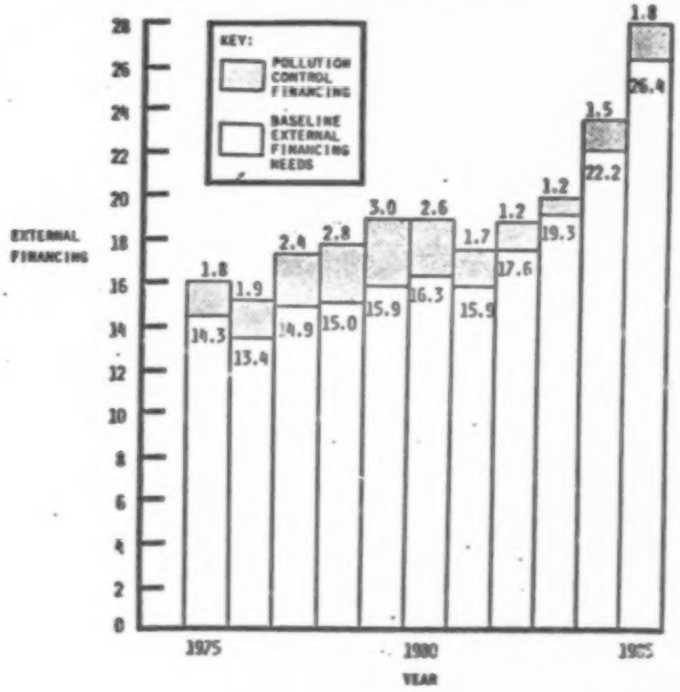
The current projections for the industry's external financing requirements are for approximately $89.8 billion

(1975 dollars) during 1975-1980, and $191.2 billion for the eleven-year period of 1975-1985. That level represents an average of approximately $17 billion per year (1975 dollars) compared to levels of approximately $4 billion in 1965 and $12 billion in 1973 (also in 1975 dollars).

As the chart below indicates, the impacts of the federal regulations fall primarily in the pre-1981 period. In the six-year period 1975-1980, increased external financing of $14.5 billion will be required; in the eleven-year period 1975-1985, that total increases only to $21.9 billion. During individual years before 1981 the impact ranges from an increase in external financing needs of from 12 percent to 19 percent, whereas the average impact in the 1981-1985 years is only approximately 7 percent.

Volume IV contains a full discussion of the significance of these impacts in terms of the industry's ability to raise this incremental financing.

EXTERNAL FINANCING NEEDS
(BILLIONS OF 1975 DOLLARS)



OPERATION AND MAINTENANCE COSTS

The operation and maintenance of pollution control equipment will naturally increase electric utility operation and maintenance expenses. In addition, however, operation and maintenance expenses will also increase to reflect the premium paid on low-sulfur fuels for those utilities complying with SO_2 regulations through the use of low-sulfur oil or coal.

The total increase in operation and maintenance expenses due to the combined air and water regulations will be $1.9 billion per year by 1980, and $3.2 billion per year by 1985 (see table below). That represents a 4 percent increase by 1980 and a 6 percent increase over the baseline projections by 1985.

As the table shows, the dominant portion of the impacts is that brought about by the air regulations--over 80 percent of the total.

ANNUAL O/M EXPENSE IMPACTS
(billion 1975 dollars)

	1980	1985
Baseline Projection	**$ 42.8**	**$ 53.8**
Impacts:		
Water Regulations	**$ 0.2**	**$ 0.5**
Air Regulations	**1.7**	**2.7**
TOTAL	**$ 1.9**	**$ 3.2**

Source: Exhibit III-2

OPERATING REVENUES AND CONSUMER CHARGES IMPACTS

The total annual cost of pollution control in the electric utility industry is equivalent to the additional revenues collected from consumers of electricity to cover those costs. In addition to the direct annual operating costs and fuel premiums, the revenues also include the appropriate amortization charges, interest, other capital costs, and increases in property and income taxes associated with pollution control equipment. The increase in operating revenues for an individual year indicates the total costs of pollution control equipment in operation for that year. The cumulative increase over a period of years (e.g., 1975-1980) represents the total amount paid by consumers for pollution control over the period. The increase in consumer charges provides a measure of that cost on a kilowatt-hour basis.

The table below summarizes the financial impacts of the combined federal air and water regulations for selected years in terms of operating revenues and consumer charges. The total premium paid by consumers for pollution control is projected to be approximately $12.2 billion (1975 dollars) during 1975-1980 and $40.2 billion in the eleven-year period 1975-1985. Those figures represent increases of approximately 3 and 5 percent resepectively over the baseline projections.

Consumer charges and operating revenues impacts at the end of those periods, in 1980 and 1985, indicate increases of approximately 6 percent. The end-of-period figures are slightly higher than the average figures because the equipment will be phased into service and not in operation throughout the entire period.

OPERATING REVENUES AND CONSUMER CHARGES IMPACTS
(1975 dollars)

	1980	1985
Consumer Charges (mills/kwh)		
- Baseline	**31.7**	**32.0**
- Impact	**+ 1.7**	**+ 2.1**
Operating Revenues (billions)		
- Baseline	**$ 74.0**	**$ 96.8**
- Impact	**+ 3.9**	**+ 6.5**
Cumulative Operating Revenues Since 1974 (billions)		
- Baseline	**$377.9**	**$812.7**
- Impact	**+ 12.2**	**+ 40.2**

Source: Exhibit III-2

The air regulations account for the largest share of the impacts by a significant margin. Due to their dominant share of both capital expenditures impacts and O/M expense impacts, they account for other 80 percent of the total impacts on operating revenues and consumer charges.

IMPACT ON THE AVERAGE RESIDENTIAL BILL FOR ELECTRICITY

To view those impacts in perspective, one must relate them to the average annual or monthly bill paid by customers. This section focuses on the impact on residential customers only; Volume VI of this report includes an assessment of the impacts on major industrial/commercial users of electricity.

The table below summarizes the projected average residential electric usage, the related electric bill, and the impacts of federal pollution control regulations upon that bill. The number of residential customers has been increasing at a rate slightly faster than the country's population growth. The continuation of that trend, together with U.S. Census Bureau projections of population growth, indicate that the number of residential customers will grow from approximately 72.1 million in 1975 to 81.6 million in 1980 and 92.7 million in 1985. The usage per residential customer is projected to increase at an annual rate slightly below 4.5 percent over the period 1975-1985. That compares to an historic rate of just over 6.0 percent per year during 1963-1973.

IMPACT OF POLLUTION CONTROL COSTS ON THE AVERAGE RESIDENTIAL ELECTRIC BILL
(1975 dollars)

	1975	1980	1985
No. of Residential Customers (million)	72.1	81.6	92.7
Usage per Residential Customer (kwh/year)	8,155.00	10,110.00	12,481.00
Average Residential Rate (mills/kwh)	37.66	40.38	40.76
Average Annual Electric Bill	$307.00	$408.00	$509.00
Average Monthly Bill	$ 25.60	$ 34.00	$ 42.40
Direct Impact of Pollution Control ($/mo.)	-	+$ 1.80	+$ 2.80
Direct and Indirect Impact of Pollution Control ($/mo.)	-	+$ 4.00	+$ 5.80

Residential rates for electricity have historically been approximately 50 percent higher than rates to commercial and industrial customers. The rationale for the difference has been that fixed costs of service for transmission and distribution equipment, lines, and metering equipment are amortized over many more kilowatt-hours of usage for commercial and industrial customers than for residential customers. The variable costs of electricity generation, primarily fuel costs, are of course not different for various customers. Thus the average rate for a customer class is composed of one component which is a system-wide average variable cost of generation for all customers, and a second component which is related to the fixed costs of service for that customer class alone.

The projections of the average residential rates shown in the table have been based upon these assumptions: first, that the historical pattern of fixed costs allocation for residential customers versus commercial and industrial customers will continue; and second, that all increases in fuel costs will be passed along equally to both customer classes. On that basis the average residential rate per kilowatt-hour is expected to increase in real terms through 1977 and then to level out and increase with inflation in current dollars. The rate is projected to increase from its 1975 level of approximately 37.66 mills per kilowatt-hour to 40.38 mills in 1980 and 40.76 mills in 1985. The average residential bill, then, is projected to increase on the basis of increased usage per customer from $25.60 per month in 1975 to approximately $42.40 in 1985.

The direct impact of pollution control expenses in terms of direct increases in residential electric bills will be approximately $1.80 per month in 1980 and $2.80 per month in 1985 (1975 dollars). Those charges represent approximately 5 percent and 7 percent, respectively.

Combined direct and indirect impacts have also been included in the table on the assumption that all impacts not passed on directly to residential customers would be charged to industrial and commercial customers, who would ultimately pass them on to residential customers in the form of price increases on their products and services. On that assumption, the eventual direct and indirect impact to residential customers will be approximately $4.00 per month in 1980 and $5.80 per month in 1985 (1975 dollars).

ENERGY IMPACTS

Scrubbers, low-sulfur coal, precipitators, and cooling towers have impacts upon the output capability of the generating plants which utilize them. Scrubbers, cooling towers, and to a very small degree, precipitators, consume electricity during operation, thereby reducing the net output of the generating plant. Thus they require that a larger number of kilowatt-hours be generated than was previously necessary in order to deliver a given level of kilowatt-hours to ultimate consumers. The additional energy required is referred to as an "energy penalty." The reduction in net capacity of the units affected is referred to as a "capacity loss."

The burning of low-sulfur coal does not inherently impact the output of a generating plant. Eastern low-sulfur coal and some Western low-sulfur coal, for example, have Btu contents above 11,000 Btu per pound and do not impact a plant's output. Some Western low-sulfur coal, however, has a heat content as low as 6,000 to 7,000 Btu per pound. When that fuel is burned, many boilers and coal-handling systems simply cannot accommodate the increased tonnage required to maintain the level of electricity generation which was previously produced with higher quality coal. That reduction in effective capacity is also referred to as a "capacity loss."

The capacity losses and energy penalties resulting from the pollution control equipment which will be installed to meet federal regulations are summarized in the table below.

CAPACITY LOSSES AND ENERGY PENALTIES
COMBINED AIR AND WATER REGULATIONS

	1980	1985
Total Industry Capacity (million kw)	631.0	751.0
Capacity Losses Since 1974 (million kw)		
Cooling Towers	0.5	4.1
Scrubbers	3.3	4.6
Low Sulfur Coal	0.2	0.2
Precipitators	0.3	0.3
TOTAL	4.3	9.2
Total Industry Energy (quads*)	25.7	33.2
Energy Penalties (quads*)		
Cooling Towers	0.0	0.2
Scrubbers	0.2	0.3
Precipitators	0.0	0.0
TOTAL	0.2	0.5

*quadrillion Btu

Note: values listed as "0.0" are too small to show up at this level of detail.

Source: **Exhibit III-2**

The total capacity losses will be approximately 9.2 million kilowatts by 1985. Those figures indicate the loss of approximately 1 percent of the industry's total capacity. The increased additions to make up the losses require an increase of approximately 5 percent in the planned level of capacity additions to 1985.

The energy penalty which will result from the operation of pollution control equipment in 1980 and 1985 is expected to be approximately 0.2 and 0.5 quads, respectively. The 1985 impact represents between 1 and 2 percent of the industry's total energy consumption.

In both categories, capacity losses and energy penalty, scrubbers and cooling towers will have approximately equal impacts and together will account for almost 90 percent of the total impacts. It should be noted that these estimates do not include indirect energy impacts such as energy to mine limestone for scrubbers or increased fuel consumption to move Western low-sulfur coal to Eastern markets.

CHAPTER 5

ASSUMPTIONS FOR ANALYSIS OF THE AIR REGULATIONS

This chapter summarizes the inputs to analysis of the Clean Air Act. The data has been provided by EPA, Sobotka & Company, and PEDCo Environmental Specialists, Inc. It is voluminous and largely contained in Exhibits II-6 through II-11 at the end of this volume. The text discusses the approach to the analysis and highlights the most significant inputs. It does not, however, attempt to repeat every item which is available in an exhibit.

This analysis of the Clean Air Act focused upon the impacts of complying with the sulfur dioxide (SO_2) and total suspended particulate (TSP) maximum emission regulations. As noted earlier, some topics were beyond the scope of this study,such as the nitrogen oxide regulations, and the significant deterioration regulations.

Furthermore, while the Clean Air Act requires compliance by all gas- and oil-burning units as well as coal-fired plants, the financial impacts virtually all fall on the coal plants. It has been assumed for the analysis, for example, that all oil-burning units would simply conform to the SO_2 regulation by burning low-sulfur oil at an incremental cost of 0.8 mills per kilowatt-hour for plants in service by 1976, and 0.75 mills for new sources (in 1975 dollars). Consequently, practically the entire discussion below is devoted to inputs relating to coal plants.

CAPACITY AFFECTED BY THE REGULATIONS

EPA and its contractors have developed projections of the extent to which each of the available SO_2 and TSP control strategies would be utilized by the industry. The projections have been developed on the basis of identifying least cost strategies for each major coal-burning region of the country. The projections have been expressed in thousand megawatts affected by:

- compliance problem (i.e., SO_2 or particulate)
- control strategy (i.e., scrubber)
- age of unit--in-service pre-1974, 1974-1976, and new sources (i.e., post-1976)
- timing of compliance--by 1980, and 1985

The coverages for coal-burning units are listed in Exhibits III-8 through III-11. They are also described below in four sets.

First, the level of pollution controls in the baseline indicate that some pollution control equipment would be utilized by the industry even without the federal regulations. In the case of the air regulations, this would generally be due to the existence of local regulations. As shown in the next table and detailed in Exhibit III-8, approximately 7 percent of coal-fired units by 1980 would be equipped with pollution control equipment which would satisfy the SO_2 emission standards even without federal regulations. The total of 30.4 million kilowatts which would be in compliance, the cost of which is not included in the impact of the regulations.

BASELINE SO_2 COMPLIANCE
FOR COAL UNITS
(million kw)

	1980	1985
Scrubbers	2.7	2.7
Medium-Sulfur Coal	8.3	8.3
Washing and Blending	7.8	7.8
TOTAL POLLUTION CONTROL EQUIPMENT	18.8	18.8
Units Burning Conforming Coal	11.6	11.6
TOTAL ALREADY IN COMPLIANCE	30.4	30.4
Capacity Requiring Controls	232.3	302.5
TOTAL COAL UNITS	262.7	332.9

Source: EPA, Sobotka & Co., Inc.
(see Exhibit III-8)

Under the baseline conditions only 30.4 million kilowatts would meet the SO_2 standard with no additional cost whatsoever. Of that, approximately one-third would simply be burning coal which conforms to the standards. The others would be plants burning low-sulfur coal, plants using washing and blending, and a very small number of primarily demonstration units with scrubbers.

Second, new sources, that is plants put into service after 1976, will be required to install permanent controls at the time they become operational. The expected compliance strategies for such systems are shown in the next table (and listed in Exhibit III-9).

NEW SOURCE (1977 AND LATER UNITS)
CONTROL STRATEGIES
CLEAN AIR ACT
(million kw)

	Coal	
	1980	1985
Scrubbers	29.1	63.5
Western Low-Sulfur Coal	30.4	66.2
TOTAL WITH POLLUTION CONTROL EQUIPMENT	59.5	129.7

Source: EPA, Sobotka & Co., Inc.
(See Exhibit III-9)

The new coal units, of which there are 59.5 million kw by 1980 and 129.7 million kw by 1985, are expected to be split almost evenly, with 49 percent installing scrubbers and 51 percent burning Western low-sulfur coal.

Third, 1974-1976 units are expected to meet the SO_2 standards through similar strategies, with 48 percent burning low-sulfur coal and 36 percent installing scrubbers. The strategies in 1985 will be the same as those in 1980; once units have adopted a strategy they are assumed to be permanently committed to it. (See table on next page.)

1974-1976 UNITS CONTROL STRATEGIES
CLEAN AIR ANALYSIS
(million kw)

	1980	1985
Scrubbers	11.5	11.5
Medium-Sulfur Coal	11.4	11.4
Western Low-Sulfur Coal	2.2	2.2
Precipitators	4.6	4.6
TOTAL WITH POLLUTION CONTROL EQUIPMENT	29.7	29.7

Source: EPA, Sobotka & Co., Inc. (see Exhibit III-9)

Fourth, the pre-1974 generating units constitute the largest amount of capacity in service, even through 1985. As shown in the table on the next page, under the current legislation, scrubbers are expected to be relied upon to bring 49.2 million kilowatts into compliance. The amount of capacity actually scrubbed (and therefore the size of the scrubbers) would be 42.9 million kilowatts, or one-fourth of all pre-1974 coal units. Those pre-1974 units would account for half of all the scrubbers installed through 1980 and one-third of those installed by 1985. Also under the regulations approximately 13 percent of pre-1974 capacity would burn medium- or low-sulfur coal and approximately 21 percent would utilize washing and blending to meet the SO_2 regulations. The same compliance strategies are assumed to apply for these units in 1985 as in 1980.

Coal conversions under the baseline assumptions in Volume II would be 14.4 million kilowatts of which 11.1 would be from oil and 3.3 would be from gas. Because of the added cost of complying with the federal air pollution standards, however, it is expected that oil to coal conversions will actually be slightly lower (9.5 vs. 11.1 million kw). In particular, it is assumed that oil-burning plants with SIPs of less than 1 percent would require a scrubber if converted to coal, and therefore would either not be converted or would convert back to oil. The 1.6 million kilowatts in the table below represent EPA's estimate of such units which would thereby meet the SO_2 emission standard. It is expected that gas conversions to oil and coal would remain virtually unchanged as a result of the regulations.

PRE-1974 UNITS CONTROL STRATEGIES
CLEAN AIR ACT ANALYSIS
(million kw)
Covered 1975-1980

	1980	1985
Scrubbers	49.2	49.2
(amount scrubbed)	(42.9)	(42.9)
Medium-Sulfur Coal	21.8	21.8
Western Low-Sulfur Coal	1.4	1.4
Washing and Blending	37.2	37.2
TOTAL WITH POLLUTION CONTROL EQUIPMENT	141.4	141.4
Already In-Compliance	30.4	30.4
Conversion to Oil	1.6	1.6
TOTAL COAL UNITS[*]	173.5	173.5

---

[*] *See reference on page III-1 of text.*

Source: EPA, Sobotka & Co., Inc.

CAPITAL COSTS

EPA has relied upon PEDCo's analysis of the best available engineering information in developing estimates of the capital costs of each of the alternative control strategies. Exhibit III-6 displays the capital costs used in the analysis. For the most expensive and most controversial units, scrubbers, EPA commissioned an independent study of operating characteristics, performance, and cost. The study, which was performed by PEDCo Environmental Specialists, Inc.[1] was made available to representatives of the utility industry for their comments.

In identifying the capital costs associated with the control strategies for coal units, EPA separately specified the costs on:

- new sources, placed into service after 1976, on which the controls were assumed to be installed during plant or unit construction
- pre-1974 units which must be retrofitted
- 1974-1976 units which also must be retrofitted.

Typical capital costs per kilowatt of capacity affected are summarized below. The complete list of capital cost estimates used in the analysis is shown in Exhibit III-6.

---

[1] *See full reference on page III-1.*

TYPICAL COSTS FOR CONTROL STRATEGIES
PRE-1974 UNITS
(1975 dollars per kw)

	SO_2 Only	TSP Only	BOTH SO_2 AND TSP
Scrubbers	$70.27	$16.56	$86.83
Medium-Sulfur Coal	-	17.40	17.40
Western Low-Sulfur Coal	49.56	17.40	62.48
Washing/Blending	5.40	1.57	6.97
Precipitators (upgrade)	-	17.40	-

Source: EPA, PEDCo (see Exhibit III-6)

The capital costs in the analysis are inflated at a rate approximately one to two points above the projected GNP rate of inflation to reflect the rise of construction costs and the experience of the electric utility industry. The rates used were 8 percent for 1976-1977, 7 percent for 1978-1982, and 6 percent thereafter.

For purposes of computing depreciation and financing (discussed later) the coal units to which these controls were applied were assumed to have the following remaining economic lives:

- new sources, 33 years
- 1974-1976 units, 30 years
- pre-1974 units, 25 years

OPERATION AND MAINTENANCE COSTS

The direct operating costs for SO_2 and particulate control technologies were also developed from the best available engineering data. These costs are expressed as incremental costs per kwh which are incurred in addition to the normal operation and maintenance costs of coal-fired units. Exhibit III-7 displays the operating cost rates used in the analysis.

The representative costs listed below should be viewed in the context of national operation and maintenance costs for coal units in 1975 of approximately 14 mills including fuel costs. The costs below do include fuel premiums for low-sulfur fuel where applicable.

TYPICAL O/M COSTS FOR CONTROL STRATEGIES
PRE-1974 UNITS
(1975 mills/kwh)

	SO_2 ONLY	TSP ONLY	BOTH SO_2 AND TSP
Scrubbers	1.40	0.30	1.70
Medium-Sulfur Coal	1.50	0.21	1.71
Western Low-Sulfur Coal	1.35	0.21	1.56
Washing/Blending	0.67	0.03	0.70
Precipitators	-	0.21	-

Source: EPA, PEDCo (see Exhibit III-7)

CAPACITY LOSS/ENERGY PENALTY

Four control strategies for coal units have capacity losses or energy penalties associated with them which are not included in either the capital or operating and maintenance costs above. The extent of the penalties is listed in the table below. It is assumed that units will be built with bypasses and that temporary variances would be granted in the event of scrubber outages. Thus, scrubbers will not cause a capacity penalty due to forced outages of a scrubber at times when the rest of a unit is available for dispatch.

COAL CAPACITY LOSS/ENERGY PENALTY

	SO_2 ONLY	TSP ONLY	BOTH SO_2 AND TSP
Scrubbers - energy penalty	3.5%	0.5%	4.0%
Medium-Sulfur Coal-capacity derate	-	0.5	0.5
Western Low-Sulfur Coal - capacity derate (loss)[1]	4.1	0.5	4.6
Precipitator-energy penaltv	-	0.5	0.5

---

[1] *Average of Western low-sulfur coal and Southwestern low-sulfur coal which have total losses of 5.5 percent and 0, respectively.*

Source: EPA, PEDCo

The energy penalty incurred by scrubbers represents the electricity required to operate the scrubbers and associated equipment. As such it represents an eventual need for incremental new coal capacity equal to 3.5 or 4.0 percent of the capacity being scrubbed. It also requires the generation of 3.5 to 4.0 percent more kilowatt-hours than were formerly produced, thereby increasing the direct production costs of the system.

The capacity derate or capacity loss incurred by switching a coal unit to low-sulfur coal is distinctly different. It represents a reduced generation (in contrast to an increased kilowatt hour need); it must be made up by increased capacity but requires no net increase in kilowatt-hour generation.

FINANCING

Financing for the compliance strategies was assumed to be accommodated through conventional sources of capital for the electric utility industry. In keeping with historical balance in the industry, common equity was assumed to maintain its 35 percent share of total capitalization, while preferred stock will stay at approximately 10 percent, and long-term debt will be 55 percent.

CHAPTER 6

ASSUMPTIONS FOR ANALYSIS OF THE WATER REGULATIONS

In December 1974, EPA published its assessment of the impacts of the final effluent regulations on the electric utility industry in a report entitled Economic Analysis of Effluent Guidelines, Steam Electric Powerplants.[1] The thermal and chemical regulations analyzed in that report remain the same today as they were then. However, industry conditions have changed so much that many of the assumptions in the previous analysis required updating. This chapter updates the earlier report in four significant ways:

- First, it revises the results based on the reduced growth baseline forecast of demand and construction (described in Volume II).
- Second, it revises the estimates of capacity which will be affected by the regulations on the basis of inputs from the EPA regional offices.
- Third, it includes the impacts of 316(b), entrainment, regulations.
- Fourth, it determines the impacts of the effluent guidelines for the 1975-1980 and 1978-1985 time periods which are consistent with the analyses of the air regulations.

---

[1] *Developed by Temple, Barker & Sloane, Inc. under contract to EPA. This chapter is a modification and extension of Chapter III, the "Analysis of the Final Effluent Guidelines," in the December 1974 report. That report remains the source for detailed descriptions of the analysis and for information on three subjects which are not reiterated here: (1) the preliminary and other proposed thermal guidelines; (2) the environmental impacts; and (3) the alternative assumptions of the Utility Water Act Group (UWAG).*

Many of the assumptions which formed the basis for the previous report were adopted from the analysis conducted by the Technical Advisory Committee on Finance (TAC-Finance) for the National Power Survey, 1973. Now, with two years' more perspective, it is clear that certain of the TAC-Finance estimates underestimated the long-term impacts of the demand and cost developments underway in 1973 and 1974.

The major changes required relate to future costs and future new plant construction activity. New or revised assumptions have been made for the following items:

- coverages (i.e., megawatts affected) of generating units which will be required by the federal guidelines to install closed-cycle cooling, or chemical treatment facilities, or both;
- costs and coverages related to compliance with 316(b), entrainment, regulations;
- inflation rates;
- financing costs;
- baseline capital costs, operating costs, and demand projections.

On the other hand, the estimates regarding the basic 1974 costs of compliance have not changed. The following assumptions from the December 1974 report have been incorporated directly into the revised analysis:

- capital costs for closed-cycle cooling and chemical treatment systems;
- operating costs for such systems;
- capacity penalties for closed-cycle cooling.

The remainder of this chapter documents both series of assumptions used in the current analysis. Coverages are presented first, then capital and operating costs, and finally energy penalties.

CAPACITY AFFECTED

In order to obtain more definitive estimates of the amount of capacity which will be affected by the guidelines, EPA surveyed the cognizant official in each EPA regional office. Detailed information was gathered from each on the coverage of the various effluent guidelines, including thermal coverages before and after Section 316(a) exemptions, and also on the extent of closed cycle cooling anticipated for the purposes of compliance with State Water Quality Standards. The responses varied significantly from region to region, and because of the differences between sites, receiving water bodies, plant characteristics, etc. across the regions, it has been very difficult to check whether a common methodology was applied consistently across regions. Nonetheless, the percentage coverages implied by the data were adopted by EPA as the basis for coverage computations in both the regional and national analyses. These coverages have been identified for three categories of capacity corresponding to the presumed construction status of plants in the industry, namely:

- Pre-1974 units are those in operation at the time of promulgation of the regulations.
- 1974-1978 units are presumed to be those under construction in 1974.
- 1979 and later units are presumed to constitute the "New Sources" category which had not begun

begun construction in 1974 and which meet new source performance standards (NSPS).[2]

The coverages are presented below for each of the three water effluent regulation categories of significance to electric utilities: thermal, chemical, and entrainment.[3]

Thermal Capacity Coverage Estimates

An evaluation of the impact of the thermal guidelines should include those expenditures associated with conversion to closed-cycle on units existing or under construction and designed for closed-cycle cooling in anticipation of the Act. At the same time, however, units designed for closed-cycle cooling for reasons other than environmental (i.e., for economic reasons) should not be included in economic and financial impacts of the Act. A majority of the units which have installed closed-cycle cooling for economic reasons have done so to compensate for an inadequate source of cooling water.

Existing Units. The degree to which existing units would be required to retrofit mechanical draft cooling towers was a major policy variable in EPA's specification of alternative guidelines to be evaluated. The final guidelines exempt all units placed into service before 1970 from the requirements to meet the limitations on the discharge of heat. Of the units placed into operation between January 1, 1970 and January 1, 1974, only the largest baseload units (i.e., those of 500 megawatt capacity or greater) are subject to effluent control under the Act. In addition to the age of the unit, the specification of these exemptions explicitly includes unit size as a factor.

---

[2] *This category was specified for analytic purposes and does not necessarily coincide with the legal definition of New Source Performance Standards (NSPS). The legal definition states that all sources which commence construction after promulgation of the final guidelines (that is, October 4, 1974) must meet NSPS.*

[3] *Exhibits III-12 and III-13 detail the percentage and kilowatt coverages, respectively, for all water regulations by 1985.*

These exemptions greatly reduce the proportion of existing units which are covered by the thermal guidelines. Based upon the survey of EPA regional offices, EPA estimated that these final regulations would cover 70 percent of existing nuclear capacity and 26 percent of existing non-nuclear capacity prior to any consideration of additional exemptions under Section 316(a) of the Act.

Section 316(a) of the Act specifies that any unit can be exempted from effluent limitation which is ". . . more stringent than necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made." The survey responses indicated that only 22 percent of nuclear and 8 percent of non-nuclear capacity placed into service prior to 1974 (i.e., existing units) would be required to convert to closed-cycle cooling after the consideration of Section 316(a) exemptions.

Units Under Construction. Simply stated, all steam electric generating units placed in service on or after January 1, 1974 are required to install closed-cycle cooling.

However, the impact of the thermal guidelines on generating units now under construction must be segmented into two categories since the cost of retrofitting a unit is significantly greater than the cost of installing mechanical draft cooling towers or an equivalent technology whenever the unit was designed for such equipment.

In estimating the required coverage for units under construction (i.e., placed in service 1974-1978), EPA first segmented this capacity into that which had been designed for (1) open-cycle, and (2) closed-cycle cooling.

All steam electric generating units which were designed for open-cycle cooling were assumed to require conversion prior to the Section 316(a) exemption while only those units which posed a high environmental risk were required to meet the thermal guidelines after this exemption. These coverage estimates were: 50 percent of nuclear and 16 percent of non-nuclear capacity before Section 316(a) exemptions, and 25 percent of nuclear and 10 percent of non-nuclear capacity after Section 316(a) exemptions.

In addition to these conversions from open- to closed-cycle, the remainder of steam electric generating units now under construction are planning to install closed-cycle cooling systems. As previously stated, some proportion of these units may be doing so in anticipation of the Act's final guidelines--and therefore, should be included in an assessment of the Act's economic and financial impact. Likewise, those units which are installing closed-cycle cooling for economic reasons or compliance with State Water Quality Standards should be evaluated but should not be included in measuring the overall impact of the Act. EPA has estimated that 25.5 percent of nuclear and 66.2 percent of non-nuclear capacity to be placed in service 1974-1978 are planning to install closed-cycle cooling. EPA estimated that 25 percent of non-nuclear units were doing so for economic reasons and 0.5 percent were doing so to comply with State Water Quality Standards (SWQS). The fossil capacity was estimated to be 24.5 percent for economic reasons, 1.7 percent for SWQS, and 40 percent to meet the federal guidelines. EPA further estimated that only 25 percent would finally be required to convert after Section 316(a) exemptions.

New Source Units. Once again, all steam electric generating units are required to install mechanical draft cooling towers or their equivalent. However, new source units, defined as those units placed in service after 1978, are assumed to install closed-cycle cooling for operation at the time the units are placed in service. Of the units to be placed in service after 1978, the EPA survey indicated that 50 percent of nuclear and 56 percent of fossil capacity are assumed to be covered before Section 316(a) exemptions. Coverage after these exemptions is assumed to be 25 percent of nuclear and 35 percent of fossil generating capacity. In addition, EPA previously estimated that 34.5 percent of nuclear and 32.5 percent of fossil capacity would install closed-cycle cooling for economic reasons during the period 1979-1990; those estimates are still being used.

Generation Capacity Affected. The total generation capacity that is required to install mechanical draft cooling towers or an equivalent technology as a result of the final thermal guidelines, after consideration of those who do so for economic reasons and those who are expected to receive Section 316(a) exemptions, is summarized in the following table.

THERMAL GUIDELINES AFTER 316(a) EXEMPTIONS

GENERATION CAPACITY COVERED*

(millions of kw)

	1975-1985
Retrofitted	
Pre-1974 Units	30.5
1974-1978 Units	18.4
Subtotal	48.9
Planned	
1974-1978 Units	20.7
1979-1985 Units	54.8
Subtotal	75.5
TOTAL	124.4

**excluding coverages for economic reasons*

Thus 124.4 million kilowatts of generation capacity will be required by 1985 to install closed-cycle cooling as a result of the Act--approximately 16 percent of the generation capacity in service at that time. Of this amount, 48.9 million kilowatts will have been retrofitted from open- to closed-cycle. This amounts to 8.5 percent of the generation capacity in service at the end of 1978 when new source standards are assumed to be applied and 7.0 percent of capacity in service at the end of 1983 when the retrofitting must be completed.

Over half of the generating capacity that is placed in service by 1985 and is covered by the Act must install closed-cycle cooling at startup. In addition to the capacity placed in service prior to 1979, 54.8 million kilowatts of the capacity brought on stream during the period 1979-1985 will be covered by new source requirements.

In total, 124.4 million kilowatts of generating capacity will be covered by the guidelines in 1985, excluding those who install closed-cycle cooling for economic reasons and those who are expected to receive Section 316(a) exemptions.

Capacity Penalty. The installation of closed-cycle cooling facilities will require the construction of additional generating capacity to operate the cooling towers and to compensate for the loss of efficiency resulting from an increase in turbine back-pressure. This capacity loss, based upon a 1 percent loss for operation of the cooling units and an additional 2 percent due to increased back-pressure, will approximate 4 million kilowatts by 1985.

Thermal Installation Schedules. The final effluent guidelines as published in the Federal Register (39 FR 36186) specify that all units which require conversion to closed-cycle cooling must do so prior to July 1, 1981 unless it can be demonstrated that such conversions would seriously impact system reliability. If system performance would be adversely affected, EPA Regional Administrators or equivalent State Authorities can accept an alternative schedule of compliance providing that the alternative schedule requires units representing at least 50 percent of the affected generating capacity meet the compliance date, that units representing at least 80 percent comply by July 1, 1982, and the remaining units comply by July 1, 1983.

In assessing the economic and financial impact of the thermal guidelines, EPA specified an installation schedule which applied the following rules of thumb for retrofitted units:

- units of 500 megawatts or greater converted for operation of closed-cycle cooling beginning in 1981;
- units of 300 megawatts but less than 500 megawatts converted for operation in 1982; and
- all other units converted for operation in 1983.

New source units and those under construction designed for closed-cycle cooling were assumed to have the cooling system operational at the time that the generating unit was placed in service.

Chemical Capacity Coverage Estimates

In addition to the above-mentioned thermal guidelines, the Act specifies chemical effluent limitations which range from pH level to suspended solids, to oil and greases, to metals in waste streams, to chlorine. These final chemical requirements as stipulated by EPA differ somewhat in concept from the above-mentioned specifications of thermal guidelines in that initial coverages are required by 1977 with additional, more stringent, requirements by 1983.

EPA originally assumed that all steam electric generating capacity will be required to meet the chemical standards. Its survey of the regional offices, however, indicated a lower level of coverage: regarding nuclear units, 70 percent for pre-1974 capacity and 34 percent for all later units; regarding fossil capacity, 61 percent for pre-1974 units and 56 percent for later units.

Thus the final chemical guidelines will apply to nearly 356 million kilowatts of generating capacity by 1985. The levels of coverage specified by the chemical guidelines are almost three times greater than those associated with the thermal guidelines over the next decade.

Chemical Installation Schedules. In assessing the economic and financial impact of the chemical guidelines, EPA specified separate installation schedules to meet the 1977 and the 1983 effluent limitation requirements. The installation schedule for the 1977 guidelines was assumed to be based on the capacity placed in service prior to 1978. This schedule is:

1974	15 percent of 1977 capacity
1975	20 percent of 1977 capacity
1976	25 percent of 1977 capacity
1977	40 percent of 1977 capacity

Capacity placed into service in 1978 is assumed to meet these requirements upon placement in service.

In addition to the above schedule, EPA specified an installation schedule to meet the 1983 guidelines which required (1) all capacity placed into service after 1978 to meet the standards at the time of initial operation, and (2) all earlier generation capacity to meet the standards according to the following time schedule:

●	1979	10 percent of 1978 capacity
●	1980	10 percent of 1978 capacity
●	1981	20 percent of 1978 capacity
●	1982	20 percent of 1978 capacity
●	1983	40 percent of 1978 capacity

Entrainment Coverage Estimates

Entrainment regulations constitute still another type of water effluent control regulation. Their objective is to prevent, through proper screening and filtration or conversion to closed-cycle cooling, the intake of living organisms with the cooling water for a generating unit. These regulations do not have exemptions or applications for economic reasons. However, the regulations do not completely cover the industry's steam electric plants.

The regulations are expected to affect only existing units and some now in construction. All new units placed in service in 1979 and later years are expected to meet the regulations through simple design changes without an increase in plant or operating costs. EPA has developed coverage estimates only for those units which would be forced to install closed-cycle cooling to meet this regulation. Approximately 14 percent of existing nuclear plants and 1.4 percent of existing fossil plants are expected to fall into that category. Approximately 3.8 percent of the 1974-1978 nuclear units and 3.5 percent of the 1974-1978 fossil units will also be impacted.

The net effect of the entrainment guidelines will be to require cooling towers on 4.5 million kilowatts of nuclear capacity and 7.4 million kilowatts of non-nuclear capacity by 1985. That total of 11.9 million kilowatts represents only 2.0 percent of the total steam electric capacity which will be in operation in 1985.

CAPITAL AND OPERATION AND MAINTENANCE COST ESTIMATES

The capital cost assumptions utilized in the economic analysis of the effluent guidelines are based on a combination of engineering estimates and surveys of actual costs experienced at existing plants wherever possible. As the first step in estimating the economic and financial impact of the Act, EPA specified the technical standards which were to be required in its Development Document of Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category (December 1974). Having specified the technical standards, EPA then sought technical sources among the equipment suppliers to the electric utility industry and among representative plants within the industry.

The estimates which resulted from that process are described below for each of the three regulations. In all cases both the capital costs for equipment and the operation and maintenance costs are expressed in dollars per kilowatt. Unless otherwise noted all cost estimates were developed in current dollars.

Thermal Guidelines Cost Estimates

The cost estimates for compliance with the thermal guidelines are based on: (1) a 1974 survey of costs incurred at existing plants; and (2) the incremental cost of installing mechanical draft cooling towers instead of open-cycle cooling on new units. These final cost estimates reflect the many comments which were submitted to EPA and which with minor exceptions were acceptable to most representatives of the electric utility industry. Exhibit III-14 details the final capital cost estimates which are summarized in the following table.

CAPITAL COST OF THERMAL GUIDELINES
(1975 dollars per kilowatt)

	Non-Nuclear Units	Nuclear Units
For retrofitted units	$24.09	$29.11
For new (planned) units	$ 5.77	$ 4.54

Source: Exhibit III-14

Clearly, the process of installing closed-cycle cooling on units which currently have open-cycle cooling and on those units which are under construction and were designed for open-cycle cooling is much more expensive than the installation cost of closed-cycle on new units. This results from the need to (1) dismantle and/or redesign the existing cooling system, and (2) absorb the total, not incremental, cost of the additional closed-cycle cooling facilities. The lower incremental cost for nuclear units being planned reflects their higher cost for open-cycle cooling--a result of plant sites located at considerable distance from sources of cooling water.

Exhibit III-15 summarizes the operating costs associated with thermal guidelines that represent the annual operating and maintenance expenses for the cooling equipment as well as associated replacement capacity. In estimating the operational impacts of closed-cycle cooling, EPA specified a capacity penalty of 3 percent which reflects:

- 2 percent due to increased turbine back-pressure, and
- 1 percent due to operating requirements for the cooling tower.

The fuel costs employed for this analysis of operating costs were based on: (1) an average heat rate of 10,000 Btu per kilowatt-hour, (2) a fuel mix of 80 percent coal and 20 percent oil, and (3) 1975 prices of $12.50 per barrel of oil and $20.00 per ton for coal.

Chemical Guidelines Cost Estimates

The cost estimates for compliance with the chemical guidelines are detailed in Exhibits III-16 to III-19. As above, the estimates have been segmented by type of capacity and age of units (year in service). The estimates are summarized in the table below.

CAPITAL COST OF CHEMICAL GUIDELINES
(1975 dollars per kilowatt)

	Non-Nuclear Units	Nuclear Units
For 1977 Guidelines		
Retrofitted Units	$ 2.01	$0.68
New (Planned) Units	1.52	0.68
For 1983 Guidelines*		
Retrofitted Units	$ 0.68	$1.92
New (Planned) Units	0.61	0.57

Incremental cost required to meet 1983 guidelines in addition to 1977 guidelines.

Source: Exhibits III-16, III-17

These costs are significantly lower than those for compliance with the thermal guidelines presented earlier. For example, the capital cost for retrofitted mechanical draft cooling towers ranges from approximately $24 to $29 per kilowatt (1975 dollars), whereas retrofitted chemical treatment costs for both the 1977 and 1983 guidelines total less than $3 per kilowatt. The lower unit cost of the chemical treatment equipment, however, is partially offset by the fact that the chemical guidelines impact significantly more generating capacity than the thermal guidelines.

The operating costs for compliance with the chemical guidelines are also relatively low. They are detailed in Exhibits III-18 and III-19 and range from a total (for 1977 and 1983 guidelines combined) of $0.31 to $0.69 per kilowatt per year (1975 dollars).

Entrainment Cost Estimates

Entrainment cost estimates were developed during 1975 by EPA for the equipment associated with its guidelines. Some plants may incorporate design modifications to prevent organisms from being drawn into the plants along with the cooling water. Other plants, however, will be required to convert to closed-cycle cooling in order to comply. The capital costs for the latter are detailed in Exhibit III-20 and are summarized in the table below.

CAPITAL COST OF ENTRAINMENT GUIDELINES
(1975 dollars per kilowatt)

	Non-Nuclear Units	Nuclear Units
Cooling Towers		
Retrofitted units	**$24.10**	**$29.05**
Units under construction	**24.10**	**19.69**

Source: Exhibit III-20

The cooling towers installed to comply with these guidelines will also result in approximately a 3 percent energy penalty, as do the cooling towers installed to comply with thermal regulations.

Compliance through the use of design modifications involves no additional operating expenses. The use of cooling towers, however, does include an operating cost associated with generation of the additional electricity to make up the energy penalty.

CHAPTER 7

COMPARISON OF CURRENT ANALYSIS OF WATER REGULATIONS AND DECEMBER 1974 RESULTS

The current cost estimates of compliance with federal water pollution control regulations have changed from those published by EPA in December 1974 in the report Economic Analysis of Effluent Guidelines, Steam Electric Powerplants.

The table below shows two very significant modifications as a result of the revised baseline estimates for the electric utility industry.

COMPARISON OF DECEMBER 1974 AND REVISED ECONOMIC IMPACTS OF THERMAL AND CHEMICAL GUIDELINES[a]

1974-1983[b]

	December 1974 Estimates		Revised Estimates
	(1974 $)[c]	(1975 $)[d]	(1975 $)
Capital Expenditures (billions)	+ $4.7	+ $5.1	+ $4.5
External Financing (billions)	+ 3.9	+ 4.3	+ 4.4
O/M Expenses (billions)	+ 0.9	+ 1.0	+ 2.1
Consumer Charges (mills/kwh at end of period)	+ 0.2	+ 0.2	+ 0.4

---

[a] *Costs for Entrainment Compliance were not estimated in the December 1974 report.*

[b] *The apparent inconsistency between time periods of 1974-1983 in the December 1974 report and 1975-1983 for the revised estimates is resolved because the megawatts of capacity assumed covered in 1974 in the earlier analysis have now been assumed to be covered in 1975 instead.*

[c] *Exhibit 68, Economic Analysis of Effluent Guidelines, Steam Electric Powerplants, U.S. EPA (December 1974)*

[d] *1975 dollars estimated at 9.5 percent inflation above 1974 dollars*

- First, capital expenditures requirements have declined primarily because reduced growth for the industry means fewer new units will be built than had previously been expected.
- Second, operations and maintenance expenses and consumer charges have increased because fuel costs have accelerated the cost of making up the energy penalties associated with closed-cycle cooling systems.

For example, the differences in the capital categories can be observed easily by comparing the kilowatts of capacity covered by closed-cycle cooling under the two sets of assumptions as shown below. Because demand growth has slackened and many capacity additions have been postponed or cancelled, the total amount of capacity which will utilize closed-cycle cooling as a result of the regulations has declined from 130.9 million kilowatts estimated in 1974 to a current assumption of 109.0 million kilowatts--a decline of 17 percent.

CAPACITY COVERED BY THERMAL GUIDELINES, AFTER 316(a) EXEMPTIONS[a]

1974-1983

(millions kw)

Type of Capacity	December 1974 Estimates	Revised Estimates
Prior to 1974, Retrofitted	10.8[c]	30.5
1974-1978 Retrofitted	23.5	18.4
Subtotal	34.3	48.9
1974-1978 Planned	34.4	20.7
1979-1983 Planned	60.7	39.4
Subtotal	95.1	60.1
TOTAL	130.9	109.0

---

[a] *excluding coverages for economic reasons*

[b] *Table, page 82, Economic Analysis of Effluent Guidelines, Steam Electric Powerplants, EPA (December 1974)*

[c] *corrected from the 12.3 figure in the published table; the remaining difference stems from lower nuclear capacity than expected*

However, while the capital-related impacts declined, the operations and maintenance and consumer charges associated with the regulations increased significantly as a result of several factors which are discussed in Volume II in terms of the revised baseline projections. Those include the following:

- substantial price increases in 1974 and later years
- increased non-fuel operation and maintenance rates as a result of labor, materials, and other factors
- the inclusion of generation not sold in the total generation requirements.

The analysis published in December 1974 has been reviewed and accepted widely. The revisions of that report presented earlier in this volume and reconciled in this chapter represent only changes which stem from revised baseline projections for the industry, in terms of both construction plans and cost escalation. The net change from the published results has been approximately a 17 percent reduction in kilowatts covered by the expensive thermal guidelines, a 12 percent reduction in capital expenditures impacts, and a 100 percent increase in operations and maintenance expenses and consumer charges.

Exhibit III-1

FINANCIAL IMPACTS OF AIR AND WATER POLLUTION CONTROLS FOR ECONOMIC AND NON-FEDERAL REASONS[1] FOR SELECTED YEARS

(dollar figures in billions of 1975 dollars)[2]

	1980	1985	1990
Capital Expenditures[3]			
Total for year	+0.2	+0.2	+0.4
Total since 1974	+1.1	+4.1	+5.7
Construction Work in Progress			
End of year	+1.9	+0.4	+0.5
External Financing			
Total for year	+1.0	+0.2	+0.3
Total since 1974	+2.9	+4.1	+5.4
Operating Revenues			
Total for year	+0.4	+1.0	+1.2
Total since 1974	+1.1	+5.2	+10.8
Operations and Maintenance Expenses[4]			
Total for year	+0.1	+0.4	+0.6
Total since 1974	+0.5	+2.1	+4.5
Consumer Charges (mills/kwh)			
Average for year	+0.2	+0.3	+0.3
Capacity Losses (millions of kw)			
Total since 1974	+0.7	+3.8	+5.9
Energy Penalty (Quads)			
Total for year	+0.4	+0.2	+0.3

[1] *Includes compliance with State Water Quality Standards*

[2] *1975 dollars assume 9.5 percent inflation in 1975*

[3] *net of CWIP increase*

[4] *excludes nuclear fuel*

Source: Ptm (Electric Utilities)

Exhibit III-2

FINANCIAL IMPACTS OF COMPLIANCE WITH THE CLEAN AIR ACT AND FEDERAL WATER POLLUTION CONTROL ACT AFTER 316(a) EXEMPTIONS FOR SELECTED YEARS[1]

(dollar figures in billions of 1975 dollars)[2]

	1980	1985	1990
Capital Expenditures[3]			
Total for year	+3.1	+1.6	+3.0
Total since 1974	+14.5	+25.0	+38.3
Construction Work in Progress			
End of year	+4.2	+3.2	+4.3
External Financing			
Total for year	+2.6	+1.8	+2.7
Total since 1974	+14.5	+21.9	+33.9
Operating Revenues			
Total for year	+3.9	+6.5	+9.3
Total since 1974	+12.2	+40.2	+80.4
Operations and Maintenance Expenses[4]			
Total for year	+1.9	+3.2	+4.8
Total since 1974	+5.8	+19.2	+39.7
Consumer Charges (mills/kwh)			
Average for year	+1.7	+2.1	+2.4
Capacity Losses (millions of kw)			
Total since 1974	+4.3	+9.2	+16.2
Energy Penalty (Quads)			
Total for year	+0.2	+0.5	+0.8

[1] *excludes impacts of pollution controls for economic and non-Federal reasons*

[2] *1975 dollars assume 9.5 percent inflation in 1975*

[3] *net of CWIP increase*

[4] *excludes nuclear fuel*

Source: PTm (Electric Utilities)

Exhibit III-3

FINANCIAL IMPACTS OF COMPLIANCE WITH THE CLEAN AIR ACT AND FEDERAL WATER POLLUTION CONTROL ACT BEFORE 316(a) EXEMPTIONS FOR SELECTED YEARS*

(dollar figures in billions of 1975 dollars)[1]

	1980	1985	1990
Capital Expenditures[2]			
Total for year	+ 3.3	+ 1.7	+ 3.2
Total since 1974	+14.8	+29.6	+43.9
Construction Work in Progress			
End of year	+ 7.2	+ 3.4	+ 4.6
External Financing			
Total for year	+ 4.2	+ 2.0	+ 2.9
Total since 1974	+17.8	+26.4	+39.1
Operating Revenues			
Total for year	+ 4.0	+ 7.5	+10.4
Total since 1974	+12.5	+44.8	+90.3
Operations and Maintenance Expenses[3]			
Total for year	+ 1.9	+ 3.5	+ 5.2
Total since 1974	+ 5.8	+20.5	+42.9
Consumer Charges (mills/kwh)			
Average for year	+ 1.7	+ 2.5	+ 2.7
Capacity Losses (millions of kw)			
Total since 1974	+ 4.6	+13.3	+21.7
Energy Penalty (Quads)			
Total for year	+ 0.2	+ 0.7	+ 1.0

[1] *1975 dollars assume 9.5 percent inflation in 1975*

[2] *net of CWIP increase*

[3] *excludes nuclear fuel*

* *excludes impacts of pollution controls for economic and non-federal reasons*

Source: PTm (Electric Utilities)

Exhibit III-4

CAPITAL EXPENDITURES IMPACTS OF COMPLIANCE WITH CLEAR AIR ACT

(Incremental to Baseline Costs)
(billions of 1975 dollars)

Control Used	SO_2 Compliance	TSP[1] Compliance	Total
		1975-1980	
Flue Gas Desulfurization	7.5	1.8	9.3
Eastern Medium Sulfur Coal	-	0.9	0.9
Western Low Sulfur Coal			
Equipment Modifications	0.6	-	0.6
Precipitators	0.3	1.7	2.0
Washing & Blending	0.2	0.0	0.2
Other Precipitators	-	0.6	0.6
SCS[2]	-	-	-
Total	8.6	5.0	13.6
		1975-1985	
Flue Gas Desulfurization	9.8	3.0	12.8
Eastern Medium Sulfur Coal	-	0.9	0.9
Western Low Sulfur Coal			
Equipment Modifications	1.3	-	1.3
Precipitators	0.3	3.9	4.2
Washing & Blending	0.2	0.0	0.2
Other Precipitators	-	0.6	0.6
SCS[2]	-	-	-
Total	11.6	8.4	20.0

[1] *Total Suspended Particulate*

[2] *Supplemental Control Systems*

Source: PTm (Electric Utilities)

Exhibit III-5

CAPITAL EXPENDITURES IMPACTS
EFFLUENT GUIDELINES POLLUTION CONTROL EQUIPMENT

(billions of 1975 dollars)

Guidelines	Fossil	Nuclear	Total
		1975-1980	
Thermal, After 316(a) Exemptions	$0.2	$0.1	$0.3
Entrainment, 316(b)	0	0	0
Chemical	0.6	0	0.6
Total	$0.8	$0.1	$0.9
		1975-1985	
Thermal, After 316(a) Exemptions	$2.4	$1.2	$3.6
Entrainment, 316(b)	0.3	0.2	0.5
Chemical	0.8	0.1	0.9
Total	$3.5	$1.5	$5.0

Exhibit III-6

CAPITAL COSTS
USED IN CLEAN AIR ACT ANALYSIS

(1975 dollars per kw)

	Compliance Problem		
Control Technology	SO_2 Only	TSP Only	Both SO_2 and TSP
		Pre-1974 Units	
Scrubbers	$70.27	$16.56	$86.83
Eastern Medium Sulfur Coal	-	17.40	17.40
Western Low Sulfur Coal	49.56	17.40	62.48
Washing and Blending	5.4	1.57	6.97
Precipitators (Upgrade)	-	17.40	-
Conforming Coal	-	45.50	-
		1974-1976 Units	
Scrubbers	$55.50	$16.56	$72.06
Eastern Medium Sulfur Coal	-	35.00	35.00
Western Low Sulfur Coal	12.50	56.00	68.50
Washing and Blending	-	-	-
Precipitators (Upgrade)	-	-	-
Conforming Coal	-	45.50	-
		1977 and Later Units	
Scrubbers	$55.50	$16.56	$72.06
Eastern Medium Sulfur Coal	-	-	-
Western Low Sulfur Coal	-	-	65.88[a]
Washing and Blending	-	-	-
Precipitators (Upgrade)	-	-	-
Conforming Coal	-	-	-

[a] *$16.00 for boiler modification, $49.88 for precipitator upgrade.*

Source: PEDCo Environmental Services, September 1976

Exhibit III-7

OPERATIONS AND MAINTENANCE COSTS USED IN CLEAN AIR ACT ANALYSIS

(1975 mills per kwh)

Control Technology	Compliance Problem		
	SO_2 Only	TSP Only	Both SO_2 and TSP
		Pre-1974 Units	
Scrubbers	1.40	0.30	1.70
Eastern Medium Sulfur Coal	1.50	0.21	1.71
Western Low Sulfur Coal	1.35	0.21	1.56
Washing and Blending	0.67	0.03	0.70
Precipitators (Upgrade)	-	0.21	-
Conforming Coal	-	-	-
		1974-1976 Units	
Scrubbers	1.15	0.30	1.45
Eastern Medium Sulfur Coal	0.67	0.35	1.02
Western Low Sulfur Coal	0.44	0.30	0.74
Washing and Blending	-	-	-
Precipitators (Upgrade)	-	-	-
Conforming Coal	-	0.33	-
		1977 and Later Units	
Scrubbers	1.15	0.30	1.45
Eastern Medium Sulfur Coal	-	-	-
Western Low Sulfur Coal	-	-	2.45
Washing and Blending	-	-	-
Precipitators (Upgrade)	-	-	-
Conforming Coal	-	-	-

Source: PEDCo Environmental Services, September 1975

Exhibit III-8

COVERAGE ASSUMPTIONS FOR BASELINE CONDITIONS FOR COAL UNITS IN 1980 AND 1985

(millions of kilowatts covered to date)

Compliance Problem/Control Strategy	1980				1985			
	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total
Out of SO^2 Compliance								
Scrubbers	-	-	-	-	-	-	-	-
Medium Sulfur Coal	-	-	-	-	-	-	-	-
Western Low Sulfur Coal	-	-	-	-	-	-	-	-
Washing & Blending	-	-	-	-	-	-	-	-
Supplemental Control Systems (SCS)	-	-	-	-	-	-	-	-
Subtotal	-	-	-	-	-	-	-	-
Out of TSP[2] Compliance								
Electrostatic Precipitators	-	-	-	-	-	-	-	-
Out of Compliance on Both SO_2 and TSP								
Scrubbers	2.0	0.7	-	2.7	2.0	0.7	-	2.7
Medium Sulfur Coal	1.8	6.5	-	8.3	1.8	6.5	-	8.3
Western Low Sulfur Coal	-	-	-	-	-	-	-	-
Washing & Blending	7.8	-	-	7.8	7.8	-	-	7.8
Supplemental Control Systems (SCS)	-	-	-	-	-	-	-	-
Subtotal	11.6	7.2	-	18.8	11.6	7.2	-	18.8
Total with Pollution Control Equipment	11.6	7.2	-	18.8	11.6	7.2	-	18.8
Capacity not Covered	161.9	22.5	59.5	243.9	161.9	22.5	129.7	314.1
Total	173.5	29.7	59.5	262.7	173.5	29.7	129.7	332.9

---

[1] *Placed in service after 1976*

[2] *Total Suspended Particulate*

Source: Environmental Protection Agency; Sobotka & Co., Inc.

Exhibit III-9

COVERAGE ASSUMPTIONS FOR COMPLIANCE WITH CLEAN AIR ACT FOR COAL UNITS IN 1980 AND 1985

(millions of kilowatts covered to date)

	1980				1985			
Compliance Problem/Control Strategy	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total
Out of SO_2 Compliance								
Scrubbers	21.8	-	-	21.8	21.8	-	-	21.8
Medium Sulfur Coal	-	-	-	-	-	-	-	-
Western Low Sulfur Coal	-	-	-	-	-	-	-	-
Washing & Blending	17.9	-	-	17.9	17.9	-	-	17.9
Supplemental Control Systems (SCS)	-	-	-	-	-	-	-	-
Subtotal	39.7	-	-	39.7	39.7	-	-	39.7
Out of TSP[2] Compliance								
Electrostatic Precipitators	31.8	4.6	-	36.4	31.8	4.6	-	36.4
Out of Compliance on Both SO_2 and TSP								
Scrubbers								
--kw Scrubbed & Precipitators	21.1	11.5	29.1	61.7	21.1	11.5	63.5	96.1
--kw Precipitators Only	6.3	-	-	6.3	6.3	-	-	6.3
Medium Sulfur Coal	21.8	11.4	-	33.2	21.8	11.4	-	33.2
Western Low Sulfur Coal	1.4	2.2	30.4	34.0	1.4	2.2	66.2	69.8
Washing & Blending	19.3	-	-	19.3	19.3	-	-	19.3
Supplemental Control Systems (SCS)	-	-	-	-	-	-	-	-
Subtotal	69.9	25.1	59.5	120.5	69.9	25.1	129.7	224.8
Total with Pollution Control Equipment	141.4	29.7	59.5	230.6	141.4	29.7	129.7	300.9
Already in Compliance	30.4	-	-	30.4	30.4	-	-	30.4
Coal Conversion to Oil	1.6	-	-	1.6	1.6	-	-	1.6
Total	173.5	29.7	59.5	262.7	173.5	29.7	129.7	332.9

[1] *Placed in service after 1976*

[2] *Total Suspended Particulate*

Source: Environmental Protection Agency; Sobotka & Co., Inc.

Exhibit III-10

COVERAGE ASSUMPTIONS FOR COMPLIANCE WITH SCS 50 PERCENT OPTION FOR COAL UNITS IN 1980 AND 1985

(millions of kilowatts covered to date)

	1980				1985			
Compliance Problem/Control Strategy	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total
Out of SO_2 Compliance								
Scrubbers	2.4	-	-	2.4	21.8	-	-	21.8
Medium Sulfur Coal	2.0	-	-	2.0	-	-	-	-
Western Low Sulfur Coal	3.9	-	-	3.9	-	-	-	-
Washing & Blending	2.1	-	-	2.1	17.9	-	-	17.9
Supplemental Control Systems (SCS)	29.3	-	-	29.3	-	-	-	-
Subtotal	39.7	-	-	39.7	39.7	-	-	39.7
Out of TSP[2] Compliance								
Electrostatic Precipitators	31.8	4.6	-	36.4	31.8	4.6	-	36.4
Out of Compliance on Both SO_2 and TSP								
Scrubbers								
--kw Scrubbed & Precipitators	5.5	4.8	29.1	39.4	21.1	11.5	63.5	96.1
--kw Precipitators Only	1.3	-	-	1.3	6.3	-	-	6.3
Medium Sulfur Coal	4.8	3.9	-	8.7	21.8	11.4	-	33.2
Western Low Sulfur Coal	7.9	7.1	30.4	45.4	1.4	2.2	66.2	69.8
Washing & Blending	2.6	-	-	2.6	19.3	-	-	19.3
Supplemental Control Systems (SCS)	47.8	9.3	-	57.1	-	-	-	-
Subtotal	69.9	25.1	59.5	154.5	69.9	25.1	129.7	224.8
Total with Pollution Control Equipment	141.4	29.7	59.5	230.6	141.5	29.7	129.7	300.9
Already in Compliance	30.4	-	-	30.4	30.4	-	-	30.4
Coal Conversion to Oil	1.6	-	-	1.6	1.6	-	-	1.6
Total	173.5	29.7	59.5	262.7	173.5	29.7	129.7	332.9

[1] *Placed in service after 1976*

[2] *Total Suspended Particulate*

Source: Environmental Protection Agency; Sobotka & Co., Inc.

Exhibit III-11

COVERAGE ASSUMPTIONS FOR COMPLIANCE WITH SCS 90 PERCENT OPTION FOR COAL UNITS IN 1980 AND 1985

(millions of kilowatts covered to date)

Compliance Problem/Control Strategy	1980				1985			
	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total	Pre-1974 Units	1974-1976 Units	New Sources[1]	Total
Out of SO_2 Compliance								
Scrubbers	7.5	-	-	7.5	21.8	-	-	21.8
Medium Sulfur Coal	6.4	-	-	6.4	-	-	-	-
Western Low Sulfur Coal	2.4	-	-	2.4	-	-	-	-
Washing & Blending	8.2	-	-	8.2	17.9	-	-	17.9
Supplemental Control Systems (SCS)	15.2	-	-	15.2	-	-	-	-
Subtotal	39.7	-	-	39.7	39.7	-	-	39.7
Out of TSP[2] Compliance								
Electrostatic Precipitators	31.8	4.6	-	36.4	31.8	4.6	-	36.4
Out of Compliance on Both SO_2 and TSP								
Scrubbers								
--kw Scrubbed & Precipitators	16.0	5.9	29.1	51.0	21.1	11.5	63.5	96.1
--kw Precipitators Only	3.2	-	-	3.2	6.3	-	-	6.3
Medium Sulfur Coal	12.7	5.2	-	17.9	21.8	11.4	-	33.2
Western Low Sulfur Coal	4.1	8.8	30.4	43.3	1.4	2.2	66.2	69.8
Washing & Blending	9.2	-	-	9.2	19.3	-	-	19.3
Supplemental Control Systems (SCS)	24.7	5.2	-	29.9	-	-	-	-
Subtotal	69.9	25.1	59.5	154.5	69.9	25.1	129.7	224.6
Total with Pollution Control Equipment	141.4	29.7	59.5	230.6	141.5	29.7	129.7	300.9
Already in Compliance	30.4	-	-	30.4	30.4	-	-	30.4
Coal Conversion to Oil	1.6	-	-	1.6	1.6	-	-	1.6
Total	173.5	29.7	59.5	262.7	173.5	29.7	129.7	332.9

[1] *Placed in service after 1976*

[2] *Total Suspended Particulate*

Source: **Environmental Protection Agency**; Sobotka & Co., Inc.

Exhibit III-12

1985 COVERAGE ASSUMPTIONS FOR WATER EFFLUENT GUIDELINES

(percent of capacity covered)

Type of Capacity	State Water Quality Standards	Economic Reasons[1]	Before 316(a)	After 316(a)	Chemical	Entrainment 316(b)
Pre-1974 Units, Retrofitted						
• Fossil	9.0%	0	26%	8%	61%	1.4%
• Nuclear	3.8	0	70	22	70	14.0
1974-1978 Units, Retrofitted						
• Fossil	0	0	16	10	0	3.5
• Nuclear	0	0	50	25	0	3.8
1974-1978 Units, Planned						
• Fossil	1.7	24.5	40	25	56	0
• Nuclear	0.5	25	0	0	34	0
1979-1985 Units, Planned						
• Fossil	1.7	32.5	56	35	56	0
• Nuclear	0.4	34.5	50	25	34	0

[1] *These estimates are from the 1974 analysis.*

Source: EPA estimates collected from Regional EPA offices, February 1976.

Exhibit III-13

1985 COVERAGE ASSUMPTIONS FOR WATER EFFLUENT GUIDELINES

(millions of kw covered)

Type of Capacity	State Water Quality Standards	Economic Reasons[1]	Before 316(a)	After 316(a)	Chemical	Entrainment 316(b)
Pre-1974 Units, Retrofitted						
• Fossil	29.1	-	84.1	25.9	197.2	4.5
• Nuclear	0.8	-	14.8	4.6	14.8	3.0
1974-1978 Units, Retrofitted						
• Fossil	-	-	13.3	8.3	0	2.9
• Nuclear	-	-	20.3	10.1	0	1.5
1974-1978 Units, Planned						
• Fossil	1.4	20.3	33.1	20.7	46.4	-
• Nuclear	0.2	10.2	0	0	13.8	-
1979-1985 Units, Planned						
• Fossil	1.8	34.5	59.4	37.2	59.5	-
• Nuclear	0.3	24.3	35.2	17.6	23.9	-
Total		89.3	260.2	124.4	355.6	11.9

[1] *These estimates are from the 1974 analysis.*

Source: Calculated from percentages in Exhibit III-12 and the baseline projections of capacity.

Exhibit III-14

CAPITAL COST GROWTH--THERMAL GUIDELINES
(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$24.09	$26.89	$36.71	$51.66
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: New Units				
$ per kilowatt	$ 5.77	$ 6.44	$ 8.79	$12.36
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$29.11	$32.58	$44.67	$62.86
% cost escalation	--	5.8%	5.4%	5.0%
Nuclear Generating Capacity: New Units				
$ per kilowatt	$ 4.54	$ 5.09	$ 6.98	$ 9.82
% cost escalation	--	5.8%	5.4%	5.0%

Source: Burns and Roe, Sargent and Lundy

Exhibit III-15

ANNUAL OPERATING COST GROWTH--THERMAL GUIDELINES
(expressed in current dollars)

	1975	1977	1983	1990
All Generating Capacity: Retrofitted Units				
$ per kilowatt	$57.46	$72.95	$106.38	$149.69
% cost escalation	--	12.6%	6.5%	5.0%
Non-Nuclear Generating Capacity: New Units				
$ per kilowatt	$57.49	$72.99	$106.44	$149.77
% cost escalation	--	12.6%	6.5%	5.0%
Nuclear Generating Capacity: New Units				
$ per kilowatt	$26.77	$29.51	$39.54	$55.64
% cost escalation	--	5.0%	5.0%	5.0%

Source: EPA estimates

Exhibit III-16

CAPITAL COST GROWTH--1977 CHEMICAL GUIDELINES
(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 2.01	$ 2.24	$ 3.05	$ 4.30
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 1.52	$ 1.70	$ 2.32	$ 3.26
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.68	$ 0.77	$ 1.05	$ 1.48
% cost escalation	--	5.8%	5.4%	5.4%
Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.68	$ 0.77	$ 1.05	$ 1.48
% cost escalation	--	5.8%	5.4%	5.4%

Source: EPA estimates

Exhibit III-17

CAPITAL COST GROWTH--1983 CHEMICAL GUIDELINES[1]

(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.68	$ 0.76	$ 1.04	$ 1.47
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.61	$ 0.68	$ 0.93	$ 1.31
% cost escalation	--	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1979-1990				
$ per kilowatt	$ 1.92	$ 2.15	$ 2.93	$ 4.12
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Placed In Service 1979-1990				
$ per kilowatt	$ 0.57	$ 0.64	$ 0.87	$ 1.23
% cost escalation	--	5.8%	5.4%	5.0%

[1] *These capital expenditures are in addition to those required to meet the 1977 guidelines.*

Source: EPA estimates

Exhibit III-18

ANNUAL OPERATING COST GROWTH--1977 CHEMICAL GUIDELINES
(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Placed In Service Prior to 1974				
$ per kilowatt	$ 0.63	$ 0.69	$ 0.92	$ 1.30
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.29	$ 0.32	$ 0.43	$ 0.61
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed In Service prior to 1974				
$ per kilowatt	$ 0.23	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed In Service 1974-1978				
$ per kilowatt	$ 0.23	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%

Source: EPA estimates

Exhibit III-19

ANNUAL OPERATING COST GROWTH--1983 CHEMICAL GUIDELINES[1]
(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Placed in Service Prior to 1974				
$ per kilowatt	$ 0.07	$ 0.08	$ 0.10	$ 0.14
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed in Service 1974-1978				
$ per kilowatt	$ 0.02	$ 0.03	$ 0.03	$ 0.05
% cost escalation	--	5.0%	5.0%	5.0%
Non-Nuclear Generating Capacity: Placed in Service 1979-1990				
$ per kilowatt	$ 0.29	$ 0.32	$ 0.43	$ 0.60
% cost escalation	--	5.0%	5.0%	5.0%
Nuclear Generating Capacity: Placed in Service 1979-1990				
$ per kilowatt	$ 0.23	$ 0.26	$ 0.34	$ 0.48
% cost escalation	--	5.0%	5.0%	5.0%

[1] *These annual operating expenditures are in addition to those required to meet the 1977 guidelines.*

Source: EPA estimates

Exhibit III-20

CAPITAL COST GROWTH--COOLING TOWERS FOR ENTRAINMENT GUIDELINES

(expressed in current dollars)

	1975	1977	1983	1990
Non-Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$24.10	$26.90	$36.67	$51.60
% cost escalation	---	5.7%	5.3%	5.0%
Non-Nuclear Generating Capacity: New Units				
$ per kilowatt	$24.10	$26.90	$36.67	$51.60
% cost escalation	--	5.7%	5.3%	5.0%
Nuclear Generating Capacity: Retrofitted Units				
$ per kilowatt	$29.05	$32.52	$44.59	$62.74
% cost escalation	--	5.8%	5.4%	5.0%
Nuclear Generating Capacity: New Units[1]				
$ per kilowatt	$19.69	$22.04	$30.22	$42.52
% cost escalation	--	5.8%	5.4%	5.0%

[1] *Units under construction*

Source: EPA Estimates

ECONOMIC AND FINANCIAL IMPACTS OF
FEDERAL AIR AND WATER POLLUTION CONTROLS
ON THE ELECTRIC UTILITY INDUSTRY

VOLUME IV

FINANCING IN CAPITAL MARKETS

MAY 1976

VOLUME IV

TABLE OF CONTENTS

Page

List of Exhibits (IV-iii)

Chapter

1 INTRODUCTION AND SUMMARY CONCLUSIONS CONCERNING ELECTRIC UTILITY FINANCING

- Introduction IV-1
- Summary Conclusions IV-2

2 RECENT TRENDS AND CYCLES IN CORPORATE BUSINESS FINANCING IV-6

- The Need for Corporate Financing IV-7
- Corporate Sources of Funds IV-9
- Inflation and the Need for External Funds IV-11
- External Funds Raised in Financial Markets IV-13
- The Cyclical Patterns of External Funds IV-14
- The Changing Corporate Balance Sheet IV-15
- Corporate External Funds Within the Financial System IV-16
- Corporate Financing in 1975 IV-18

3 FUTURE PROJECTIONS OF CORPORATE FINANCIAL NEEDS IV-19

- The Determinants of External Financing IV-19
- Three Alternative Scenarios for 1975-1985 IV-22
- Corporate External Needs in Competition With Other Sectors of the Economy IV-26
- The Supply and Demand for Funds in Three Alternative Scenarios IV-29
- Variations Within a Credit Cycle IV-34
- Conclusions IV-34

Chapter | Page

4 ELECTRIC UTILITY INDUSTRY FINANCIAL RESULTS AND FINANCING, 1960-1975 IV-36

1960-1965: Growth and Prosperity IV-36

1966-1973: Growth Without Prosperity IV-40

1974: Financial Nadir? IV-48

1975 IV-52

5 PROJECTIONS OF ELECTRIC UTILITY INDUSTRY FINANCING, 1975-1985 IV-54

The Industry's Financing Requirements IV-54

Investor-Owned Electric Utility Needs Versus Available Funds and Total Corporate Needs IV-55

Projected Financial Strength of Investor-Owned Utilities IV-60

Concluding Comments IV-66

6 FINANCING PROBLEMS OF INDIVIDUAL SYSTEMS IV-68

Three Categories of Financial Health IV-68

Intercompany Comparisons of Returns and Interest Coverage IV-71

Determinants of Interest Coverage Ratios IV-75

Conclusions Concerning Electric Utility Financing Problems IV-78

Appendix

IV-A THE EFFECTS OF ISSUING STOCK AT DIFFERENT MARKET PRICES RELATIVE TO BOOK VALUES IV-121

VOLUME IV

LIST OF EXHIBITS

Exhibit

IV-1 Total Uses of Funds and Financing Need by Year; Domestic Non-Financial Business Corporations, 1960-1974

IV-2 Uses of Funds and Financing Needs in the Five Credit Cycles; Domestic Non-Financial Business Corporations

IV-3 Sources of Funds by Year; Domestic Non-Financial Business Corporations, 1960-1974

IV-4 Sources of Funds in Five Credit Cycles; Domestic Non-Financial Business Corporations

IV-5 The Cycles of External Funds--Short-Term Debt, Long-Term Debt, Net Equity Issues; Non-Financial Business Corporations

IV-6 Levels of Liquid Assets and Debt Outstanding, as Percent of GNP; Non-Financial Business Corporations

IV-7 Net Increase in Financial Liabilities by Year; Major Economic Sectors, 1960-1974

IV-8 Corporate Business Debt Financing as a Percent of Total Private Sector Debt Financing

IV-9 Projections of Future Sources and Uses of Funds; Domestic Non-Financial Business Corporations

IV-10 Savings Behavior of U.S. Households

IV-11 Projections of Total Capital Needs by Year; Domestic Non-Financial Business Corporations, 1975-1985

IV-12 Net Income; Privately Owned Class A&B Electric Utilities in the United States Electric Department, 1960-1974

IV-13 Earnings and Dividends; Privately Owned Class A&B Electric Utilities in the United States Electric Department, 1960-1974

Exhibit

IV-14 Assets Per Dollar of Revenue; Privately Owned Class A&B Electric Utilities in the United States Electric Department, 1960-1974

IV-15 Annual Capital Expenditures Vs. Total Assets; Privately Owned Electric Utilities in the United States Electric and Gas Departments, 1961-1974

IV-16 Sources of Funds; Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-17 Capital Structure; Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-18 Long- and Short-Term Debt; Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-19 Market Value Vs. Book Value and Price/Earnings Comparisons; Moody's Public Utility Index, 1960-1974

IV-20 External Sources of Funds; Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-21 Yield and Yield Spreads of Aa Utility Bonds, 1960-1975

IV-22 Interest Charge Coverage; Privately Owned Class A&B Electric Utilities in the United States Electric Department, 1960-1974

IV-23 Embedded Interest Rate on Long-Term Debt; Privately Owned Class A&B Utilities in the United States Electric Department, 1960-1974

IV-24 Allowance for Funds Used During Construction Vs. Capital Expenditures; Privately Owned Class A&B Electric Utilities in the United States Electric Department, 1960-1974

IV-25 Electric Utility New Plant and Equipment Expenditures Vs. All Industry Plant and Equipment Expenditures; Privately Owned Electric Utilities in the United States, 1960-1974

Exhibit

IV-26 Net Financing Electric Utility Industry Vs. Non-Financial Business Corporations; Privately Owned Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-27 Gross Equity Financing Electric Utility Industry Vs. Total Private Sector; Privately Owned Electric Utilities in the United States Electric and Gas Departments, 1960-1974

IV-28 Downgrading of Electric Utility Securities, 1965-July 1974

IV-29 Issue and Recent Market Prices--15 Recent Electric Utility Bond Issues

IV-30 Projections of External Financing Requirements for Investor-Owned Electric Utilities, 1975-1985

IV-31 Illustration of Electric Utility and Corporate Net External Funds Required as Percent of Net Savings in the Household Sector

IV-32 Interest Coverage Projections Before Pollution Control Financing For Investor-Owned Electric Utilities, 1980 and 1985

IV-33 Interest Coverage Implications of Pollution Control Financing for Investor-Owned Electric Utilities; With Historical Capital Mix, 1980 and 1985

IV-34 Interest Coverage Implications of Pollution Control Financing For Investor-Owned Electric Utilities; With Equity Only, 1980 and 1985

IV-35 Interest Coverage Implications of Pollution Control Financing For Investor-Owned Electric Utilities; With Industrial Revenue Bonds at 6.6 Percent, 1980 and 1985

IV-36 Determinants of Interest Coverage Ratios

IV-37 The Impact of AFDC on Interest Coverage Ratios

CHAPTER 1

INTRODUCTION AND SUMMARY CONCLUSIONS CONCERNING ELECTRIC UTILITY FINANCING

INTRODUCTION

Volumes II and III of this report have discussed the electric utility industry's future in terms of demand, capacity, capital expenditures, generation, revenues, operating and maintenance expenses, etc. under the assumption that the external financing needs consistent with all these other projections can, in fact, be met. This volume addresses itself to the validity of that assumption.

Because the electric utility industry's ease of access to external financing is in part determined by the industry's own financial strength and in part by overall capital market conditions, the analysis in this volume comprises historical reviews and projections both of total non-financial corporate financing needs vis-a-vis total U.S. sources and uses of funds and of total electric utility financing needs vis-a-vis other non-financial corporations and total sources and uses of funds.[1] Chapter 2 presents a discussion of recent trends and cycles in total corporate financing. Chapter 3 discusses possible future trends in total corporate financing, in the funds required to finance governmental and housing expenditures, and in household savings. Chapter 4 reviews the electric utility industry's financing history. Chapter 5 then examines the industry's probable future needs, both before and after consideration of the requirements associated with federal pollution control regulations, in the context of total capital market conditions.

---

[1] *TBS was assisted by Professor Jay Light of the Harvard Business School in the capital market analysis of this volume and has drawn heavily on data developed by him for a forthcoming book, Capital Markets.*

Financial projections for the electric utility industry as a whole tend to obscure variations in the financial strength and access to financing of firms within the industry. Chapter 6 discusses these differences among firms and suggests methods for alleviating the difficulties of the weaker firms in the industry.

The emphasis in this volume is on investor-owned firms. The financing needs of public companies are noted briefly, but are not discussed in detail because of the variety of entities and patterns of financing involved. Because many of the public firms depend directly on governmental funding or on indirect governmental guarantees, their access to funds is in most instances relatively assured, provided the governmental unit in charge gives its approval to the financing. Thus, most public firms are unlikely to be "crowded out" in the competition for funds in the capital market because of weak credit ratings. And, their financing is perhaps best viewed as part of the financing of the government sector.

SUMMARY CONCLUSIONS

As is discussed in Chapter 5, it is quite probable that the electric utility industry's future financing needs will be significantly above historical levels relative to other corporate financing and to total U.S. sources and uses of funds. Assuming that household savings in the future continue to be at their historical average of 6 percent and assuming that the real growth rate in GNP is 3.5 percent, the industry's future net external financing needs will increase from an historical high of 11.5 percent of household net savings in the 1970-1974 credit cycle to a level of 12.5 percent in the 1975-1985 period even before consideration of pollution control expenditures. Pollution control financing is projected to raise the industry's requirements to 14 percent of net household savings. The foregoing projections presume a return on equity of 14 percent, a level well above the level of 11 percent characteristic of recent years. The industry's external financing needs would be slightly higher, and its difficulties in raising these external needs substantially higher, if returns remain at only 11 percent.

As is discussed in Chapter 3, the productive capacity and energy shortages of 1973 and 1974 have caused some observers to predict that the electric utilities' financing will take place in the context of very tight overall capital market conditions. In these projections, the financing needs of all non-financial corporations may be as high as 83 percent of net household savings. If total corporate financing needs are as high as envisioned in this scenario, it is clear that utilities will be competing for record levels of funds in extraordinarily tight capital markets. However, it is within the power of state regulatory commissions to grant price increases sufficient to enable utilities to "crowd out" many weaker corporate borrowers. And, the extremely high levels of total corporate financing needs envisioned in this scenario will occur with only low probability.

A more likely projection of total corporate financing needs is that non-financial corporations will require funds equal to about 63 percent of net household savings. This 63 percent corporate share of net household savings compares with a 65 percent share in the last credit cycle and a 58 percent share in the 1967-1970 credit cycle. While this level of total corporate financing implies relatively tight capital market conditions, a modest increase in the current financial health of the electric utility industry should enable it to compete successfully for the amounts of funds required in the 1975-1985 period.

If total non-financial corporate demand for financing is lower than the levels of the most recent credit cycle, as is likely, the future of capital market conditions will be relatively easy. If so, however, the electric utility industry's share of total corporate financing will be enormous. Before consideration of pollution control financing, the industry's needs would rise to 32 percent of the corporate sector's total. With pollution control financing, the industry's share would rise to 36 percent. Such shares are possible, but only if utilities have very strong financial statistics. Unless regulators allow returns on common equity and interest coverage ratios that allow the electric utility industry to regain its status of the 1960s as a low-risk industry, investors may be very unwilling to commit such a high percentage of their corporate investment portfolio to the industry.

As is argued in Chapter 6, even if adequate sources of funds are available for the industry as a whole and even if the industry's financial strength is, on average, adequate to enable it to compete effectively for these funds, some firms may still have difficulty in finding capital. The industry average ratios have historically been the aggregate of individual company ratios that vary widely. Thus, if the industry's average rate of return on equity is just at or is below the rate of return demanded by investors, a number of firms would have returns on equity and interest coverage ratios that would severely hamper their access to external financing. In fact, some firms are currently unable to finance desired basic capacity additions and thus can expend funds for pollution control equipment only by further cuts in their baseline needs.

Some individual electric utilities may be able to improve their financial health by further improvements in efficiency and by reductions in service, but the resolution of the financing difficulties faced currently by a number of utilities is perhaps more in the hands of regulators. Even if a company is able to reduce its operation and maintenance expenses or its capital investment costs, an improvement in its financial health requires that the company be allowed to retain some portion of these savings. Pollution control revenue bonds and reductions in debt ratios have been advanced as solutions for the financing problems facing some companies, but TBS's judgment is that neither will substantially alleviate these companies' financing difficulties. While these alternatives may improve interest coverage, the first alternative will not help and the second alternative may hurt these companies' efforts to issue common stock at reasonable prices. Thus, the basic requirement for returning ailing companies to financial health is an increase in revenues, which is within the power of regulatory commissions.

In many instances, the price increase required to restore individual companies to financial health is simply the relatively small increase required to bring returns on equity to levels demanded in the marketplace by investors. In some instances, however, the increases may take a form different from those associated with providing an adequate return on equity. The increases may, for example, result from a conversion from flow-through accounting to normalized accounting or from the inclusion of construction work in progress in a utility's rate base.

CHAPTER 2

RECENT TRENDS AND CYCLES IN CORPORATE BUSINESS FINANCING

Electric utility financing in recent years has taken place as part of a rapid increase in financing needs throughout the corporate sector. In the late 1960s and early 1970s, corporate demands for external funds became the largest and fastest growing element of financial needs throughout the economy. Indeed, in the credit crunches of 1966, 1969-1970, and 1973-1974, these needs became so large that they created strains throughout financial markets and "crowded out" other potential borrowers. By 1975, an increasing recognition of the importance of these growing and cyclical corporate financial needs was reflected in a number of projections of future financial markets. Despite very modest external corporate needs in 1975, a number of financial forecasters remained concerned about the possibility of a future "capital shortage" caused in part by the external financing needs of corporations.

In order to gain insight into future total corporate external financing needs and capital market conditions, and thus into future conditions affecting the electric utility industry, this chapter contains an analytical review of recent trends in total non-financial corporate financing. In addition, in order to show their importance within the overall financial system, these corporate financial needs will be compared with the financing of other economic sectors.

THE NEED FOR CORPORATE FINANCING

In order to evaluate the underlying demand for funds in the corporate sector, TBS has focused on the non-financial corporate business sector as defined in Flow of Funds Accounts, published by the Federal Reserve Board (FRB). (This sector includes only domestic non-financial business corporations, and excludes financial corporations, whose demands for funds are derived from the financing needs of others and whose inclusion would therefore "double-count" some financing.) Exhibit IV-1, derived from the FRB Flow of Funds data, displays the total uses of funds, and therefore the total funds needs, of non-financial business corporations over the previous 15 years. These total financing needs have grown from $44 billion in 1960 to $163 billion in 1974.

Total corporate financing needs comprise two major components:

- The need for additional real assets (plant and equipment, residential construction, and inventory); and
- The need for increased financial assets (liquid assets, accounts receivable, etc.)

In addition, about 10 percent of the total uses of funds cannot be categorized due to data deficiencies, and these are included in the item "discrepancy." As shown by Exhibit IV-1, new plant and equipment generally accounted for from 65 to 80 percent of non-financial business corporations' total financing needs in the last 15 years and is consequently the dominant component of these needs.

Interpretations of the raw data of Exhibit IV-1 are complicated by two factors. First, while the number of uses of funds has been increasing rapidly, this growth could simply be due to the overall economic growth and inflation of recent years. Second, there are apparent cyclical swings in these and other financial data which may obscure and confuse the underlying secular trends.

In order to clarify the information as far as possible, the last two decades have been divided into five non-overlapping credit cycles which correspond generally to the economic cycles of recent years: the final two cycles of the 1950s, the credit cycle of the early 1960s which culminated in the credit crunch of 1966, the credit cycle (some would say "mini-cycle") of the late 1960s, and the credit cycle of 1970-1974 which culminated in the credit crunch of 1973-1974[1]. Within each of these credit cycles, the various corporate uses of funds will be shown as a percent of gross national product (GNP) to normalize them in respect to the prevailing size of the economic and financial system. Most of the data which follow will be displayed in the same manner, to provide some insights into secular changes within the last two decades.

---

[1] *More precisely, the cycles are each composed of a series of consecutive calendar quarters as follows: 1954:3 through 1958:1; 1958:2 through 1960:4; 1961:1 through 1967:1; 1967:2 through 1970:3; and 1970:4 through 1974:4.*

Utilizing these definitions of credit cycles, Exhibit IV-2 documents the secular trends in corporate financing needs in connection with GNP over the last two decades. "Total Financing Needs," the total of all the separate uses of funds, increases in a relatively steady pattern over these cycles. The most important source of this increase is plant and equipment investment, but inventories and net financial assets also contribute to the secular trend.

CORPORATE SOURCES OF FUNDS

The total financing needs of corporations must be met from one of two principal sources: internally generated funds, composed of adjusted retained earnings[2] and depreciation, or externally raised funds. Exhibit IV-3 shows how the total financing needs of corporations have been funded over the last 15 years. Although internally generated funds gradually have grown from $34.4 billion in 1960 to $81.5 billion in 1974, as a percentage of total financing needs, they declined from 78 percent in 1960 to only 50 percent in 1974. Exhibit IV-4 shows these same sources of funds as a percentage of GNP over the five credit cycles defined above.

Exhibits IV-3 and IV-4 document what has probably been the most important recent trend in financial markets: the increasing need for external funds to fill the "gap" between total financing needs and internally generated funds. More precisely, from the first to the third credit cycle, industry's total financing needs grew substantially, but they were accompanied by an almost equal expansion of internally generated funds, which made the external funds raised in financial markets relatively stable. Conversely, from credit cycle 3 to credit cycle 5 total financing needs continued to increase, but internally generated funds shrank as a percent of GNP. This resulted in the external funds raised by non-financial corporations expanding rapidly from 2.7 percent to 5.1 percent, almost doubling as a percent of GNP. And, of course, the external funds measured in absolute dollars expanded even more rapidly, as is shown in Exhibit IV-3.

---

[2] *Adjusted retained earnings (or adjusted retained profits) are retained earnings adjusted for inventory valuation profits which provide no cash flow. See the definitions accompanying Exhibit IV-3 for further explanation.*

In addition to external funds raised, it is useful to have a measure of the net extent to which corporations have demanded funds from the financial system. While the external funds raised in financial markets withdrew funds from the financial system, the increase in liquid financial assets on corporate balance sheets has served as an offsetting supply of funds. In Exhibit IV-4 this net measure of corporate financial demands, "net external funds required," is computed for each past credit cycle. As shown in Exhibit IV-4, net external funds have also expanded rapidly, from an average of 2.4 percent of GNP in credit cycle 1 to 4.3 percent of GNP in credit cycle 5.

In brief, these external needs have been the cause of recent concern about the ability of the U.S. financial markets to accommodate needed corporate financing. Through the last several cycles of expanding investment needs, the internally-generated funds of corporations have declined, opening up a severe cash flow "gap" which could only be filled by external funds. Or, to interpret the facts somewhat differently, in a time when corporations have found it increasingly difficult to generate internal funds, they have nonetheless maintained and even expanded their rate of investment and then have funded this investment through external financing, primarily borrowing.

INFLATION AND THE NEED FOR EXTERNAL FUNDS

One of the most important factors leading to the external funds requirements of recent cycles has been the accelerating pace of inflation. Inflation affects the operational financial needs of corporations in several ways. Inflation (1) raises the current or nominal cost of any new plant and equipment, inventory, or financial asset expansion needed to support real growth; (2) raises the cost of replacing the inventories and the plant and equipment that are consumed in the production process; and (3) increases the dollar amount of financial assets required to maintain a given volume of real business activity. Consequently, inflation leads to an expanded need for funds. Inflation has caused much of the increase in the ratio of total financial needs to GNP shown in Exhibit IV-2.

Inflation also affects the capacity of firms to generate funds internally. Inflation leads to higher wage rates, higher unit labor costs, and increased production costs. Expectations of inflation affect interest rates and the level of interest payments.

The corporate income tax system is another major force through which inflation affects businesses' internal funds. When computing income for tax purposes, corporations are allowed to charge depreciation only on the basis of historic cost. As a result, taxable income is overstated in connection with the cash flows that can be invested in net new assets by the difference between depreciation based on historic costs and depreciation based on replacement costs. Similarly, the interaction of the corporate tax system and inflation can also produce an unnecessary cash outflow in the form of higher taxes when inflationary price increases lead business firms to replace inventories at higher price levels. Essentially, firms have paid taxes upon inventory profits which were not available for net new investment.

As illustrated in Exhibits IV-3 and IV-4, total financing needs increased during the inflationary period of 1971-1974. However, even though business prices rose substantially, internal funds did not grow commensurately. The inflation resulted in wage and salary payments taking a larger share of the total revenues generated by corporations. An increased outflow of tax payments in connection with the replacement cost of plant and equipment inventories reduced internal funds as well.

During inflationary periods there have often been enormous political pressures to hold down prices. These pressures can take the form of "jaw-boning" from public officials, or, as in recent periods, direct controls. Furthermore, in recent years, corporations have found it difficult to raise prices because of reduced consumer demand. For these reasons, corporations recently have been unable to maintain their internally generated funds in inflationary periods, and increasingly have turned to external sources of funds.

EXTERNAL FUNDS RAISED IN FINANCIAL MARKETS

External funds can be raised in financial markets in the form of increased short-term debt, increased long-term debt, or new equity issues. The principal source of short-term debt for corporations has been the commercial banking system. To some extent, large corporations with prime credit ratings can supplement this use of bank debt with their own short-term promissory notes, called commercial paper. Some corporations use other sources of short-term debt such as finance company loans. A special component of short-term debt, usually called the profit tax liability, arises through the normal process of paying taxes.[3] Taken together, however, the profit tax liability, commercial paper, finance company loans, and other miscellaneous loans form only a small portion of corporate debt. Recently, bank debt has dominated the total sources of short-term funds.

---

[3] *Since profit taxes are not paid in cash exactly as they are accrued, corporations have a short-term liability to the government--profit taxes payable--at the end of any quarter or year. In times when profits and taxes are rising, the size of this liability also rises, providing a form of short-term financing to corporations. In the 1950s, when there was a significant lag in the processing of tax collections, this short-term liability sometimes was a significant portion of total short-term finance. Recently, however, as the schedule of tax collections has accelerated, the profit tax liability has become relatively unimportant.*

In addition, commercial banks have often made term loans to corporate business. Over one-third of all bank loans in recent years have been term loans. These term loans generally are considered to be intermediate-term finance, longer than one year (the arbitrary breakpoint for most definitions of short-term debt) yet shorter than the typical 15- to 30-year maturities of "long-term debt." However, because of definition problems and corresponding deficiencies in the data, all bank loans are included in the "short-term debt" category in the analysis of this volume.

THE CYCLICAL PATTERNS OF EXTERNAL FUNDS

This discussion has concentrated thus far on the secular trends in external financial needs within the corporate sector, by averaging the observed flows-of-funds across credit cycles. Within each cycle, however, there are marked variations in financing activity caused by the cycles in inventory accumulation and, to a lesser extent, by plant and equipment spending. Toward the middle or end of each credit cycle, corporate external funds requirements have reached their cyclical peak.

Exhibit IV-5 displays the changing patterns of corporate external funds. In addition to the cyclical nature in the total of these new funds, there appears to be a cyclical pattern in their composition. In the early phases of each credit cycle, long-term sources of funds (particularly long-term debt) are the principal sources of new funds. Towards the middle of each credit cycle, as total new funds are usually accelerating rapidly, a shift occurs away from a primary reliance upon long-term debt and toward short-term debt. Toward the end of each credit cycle, in the economic recession or slow-down, long-term debt resumes its role as the principal source of external funds.

This typical pattern is evident in the data for the most recent credit cycle. In 1971 and early 1972, long-term capital, particularly long-term debt and net new equity issues, provided over $41 billion, or about 85 percent of the new external funds of corporations. In the face of rising needs in 1973, however, these sources both decreased. By early 1974, historically large quantities of short-term debt, over $45.3 billion, had become the mainstay of corporate external financing. Most of this finance was provided through the commercial banking system, and the size of banks grew rapidly in this period to accommodate these short-term needs; however, by the final quarter of 1974 and throughout 1975, this short-term debt decreased sharply and was replaced once again by the rapidly growing contribution of long-term funds.

THE CHANGING CORPORATE BALANCE SHEET

Recently, there have been several important secular trends in corporate balance sheet ratios: increasing levels of debt in connection with equity, a changing ratio of short-term debt to long-term debt, and decreasing relative levels of liquid asset balances. (Exhibit IV-6 illustrates the changing levels of debt and liquid assets as a percent of GNP.) These trends have contributed to a more debt-heavy, and perhaps more fragile, corporate financial structure.

The limits to these financial trends are not obvious. On the one hand, corporations in some other countries have continually operated with debt ratios that are high by U.S. standards. A comparison with other countries would suggest the U.S. corporations should have relatively little to fear from their new financial structures. On the other hand, some observers recently have suggested that the corporate sector should not, and indeed will not, increase its debt financing beyond the levels reached in the mid-1970s.

Corporate External Funds Within the Financial System

Business corporations are only one of the seekers of funds in the financial markets. The other important demands come from households (for both home mortgages and consumer credit) and from governments. The recent patterns of these other credit demands as compared to corporate demands are shown in Exhibit IV-7. The dominant conclusion that emerges from these data is that both corporate external financing and the borrowing of other sectors rose during this period. The combination of inflation, fiscal and monetary policies of government, and financing and saving decisions of various private sectors gave rise to a total expansion of financial assets and liabilities (credit). The frequently described rise in corporate external funds was the dominant factor in this expansion, increasing from $10 billion in 1960 to $81.5 billion in 1974. It was accompanied by smaller increases from other sectors. As a result, corporate business liabilities grew from 34 percent of the total in 1960 to 54 percent of the total in 1974.

The total financing of all sectors is limited by the rate of growth of total credit, which is determined partly by the financial decisions of savers and partly by the decisions of the Federal Reserve Board. The various credit seekers must compete for a limited supply of financing. Business corporations appear to be relatively effective competitors for funds because of their insensitivity to interest costs. Households appear to be the economic sector most likely to be "crowded out" during a credit crunch because of their relative sensitivity to interest costs. This process is illustrated in Exhibit IV-8, which records corporate debt financing as a percent of all private sector debt financing. Corporations have been taking a secularly increasing percentage of the total financing available to the private sector. In a credit crunch, when the Federal Reserve restricted the overall growth of credit but corporate external needs were still large, these percentages were particularly high.

In 1966-1967, 1970, and 1973-1974, the corporate sector obtained about 60 percent of the available financing ($62 billion in 1973 and $77.5 billion in 1974) and the borrowing of households was curtailed severely. Faced with the high interest costs of these periods, households decided to reduce their rate of borrowing. This "crowding out" of households has had important implications for economic activity. It probably was the primary cause of the great cycles in new home construction in these periods. While there is some disagreement as to the reasons involved in this "crowding out" of home mortgage and other household borrowings, there is agreement that it has in fact occurred during each of our recent credit crunches. It is generally believed that the potential borrowing of small businesses, larger financially weak businesses, and state and local governments is also influenced by interest costs, and is likely to be curtailed during times of tight credit. If the external financial needs of corporations, particularly large credit-worthy corporations, grow, the likelihood is that there will be less financing available for the more interest-sensitive borrowers: households, small businesses, state and local government, and large but financially weak corporations.

CORPORATE FINANCING IN 1975

The severe recession of 1975 resulted in some major changes in the pattern of corporate financing. Plant and equipment spending eased somewhat and there was a massive inventory liquidation. These events combined to reduce the total financial needs of corporations, while internally generated funds fell only slightly. The result was a substantial reduction in the external funds required raised by non-financial corporations in the first half of 1975, declining in that period to about 1.8 percent of GNP. Compared with the recent levels of 5 and 6 percent of GNP shown in Exhibit IV-5, this is a dramatic reduction. Furthermore, liquid asset balances were increased and short-term debt was drastically reduced by the massive new issues of long-term debt in 1975. These changes are not particularly surprising, however, given the recession and especially the rate of inventory liquidation accompanying the recession of the last two years.

CHAPTER 3

FUTURE PROJECTIONS OF CORPORATE FINANCIAL NEEDS

As documented in Chapter 2, there has been very rapid growth in the net external funds required by non-financial corporations over the last three credit cycles, that is, the last 15 years. And, these external funds requirements have at times placed considerable strain on the U.S. financial markets. Thus, an important factor in judging the ability of the electric utility industry to meet its future financing needs is the future external financing needs of other non-financial corporations. This chapter describes and analyzes three possible patterns of corporate investment and external financing requirements through 1985.

THE DETERMINANTS OF EXTERNAL FINANCING

In 1975, the external financing needs of corporations plummeted, but many observers still expect a future "capital shortage," caused largely by the investment plans of corporations. The major projected investment need is to expand productive capacity. In recent years, the U.S. economy experienced severe shortages of many economic goods, as installed productive capacity was insufficient to meet the demands of the economy, particularly in the basic materials industries (metals, chemicals, paper, etc.).

The cause of the shortages in the basic materials industries is complex. First, capacity additions in several of these industries were modest throughout the 1960s, particularly in comparison with several earlier periods. Second, the worldwide economic boom of 1972-1973 contributed to worldwide shortages in many basic materials. Third, the devaluation of the dollar made U.S. materials more attractive on a price basis and thus contributed to U.S. capacity problems. The high resultant operating ratios in the basic materials industries during 1973 led many observers to conclude that substantial additions to plant capacity will be required to reduce the threat (or capitalize on the opportunity) of future demand and supply imbalances and to attenuate wide price fluctuations in the basic materials industries.

In addition to the basic materials industries, energy production and conservation may entail major new investment. The investment in energy production will comprise expenditures both for oil exploration and for the development of alternative energy sources. Energy conservation will involve investments in mass transportation facilities, more efficient industrial processes and equipment, better insulation, etc.

Furthermore, pollution control expenditures will increase the plant and equipment spending in a number of key industries. These expenditures include investments to achieve compliance for existing capacity or to replace old capacity that cannot economically be brought into compliance. Moreover, the effective per unit cost of new plant and equipment additions will be increased by those requirements.

In view of the possible capacity additions within the basic materials industries, the possible need for high levels of investment in energy-producing and energy-consuming industries, and stricter pollution control requirements, the total U.S. investment in plant and equipment could be considerable in coming years. Financing this increased plant and equipment investment could be a major challenge for the U.S. financial system in the coming decade.

On the other hand, despite these widely circulated predictions of increased investment needs, it is not at all clear that the expected plant and equipment spending will actually materialize. The economy is just now recovering from the severe recession of 1974-1975 and capacity utilization rates within most industries are very low by historical standards. Thus, in a broad range of domestic industries, there is certainly no current shortage of capacity. In 1975, real plant and equipment spending declined, reflecting the reduced incentives for capacity expansion. Moreover, the attitudes of many corporate managers towards the trade-off between growth and profitability may be changing subtly. The great external financial needs of the early 1970s resulted from corporate decisions to continue investing in new real assets, even though the cash returns from existing assets were severely depressed by historical standards. This was the basic cause of the large external financing needs in recent credit cycles.

With the memory of these years still fresh, many managers may choose to alter their objectives and plans with respect to expansion. Before embarking on new plant and equipment expansion plans, they may first require an enlarged cash flow and profit stream from existing assets, so that the expansions can be financed in large part through internal funds. If the internal funds cannot be generated, they may just scale back their investment in new capacity until the profits do recover. If, as current readings would suggest, corporate attitudes and decisions have changed in this way, they could have important ramifications for both future investment rates and external financial needs.

THREE ALTERNATIVE SCENARIOS FOR 1975-1985

The current economic and financial cross-currents make it difficult to estimate the 1975-1985 external financing requirements of corporations with any confidence or certainty. On the one hand, the investment needs apparently required to satisfy both private and public goals seem large. On the other hand, current capacity utilization figures suggest a much less immediate need. Additionally, there is a growing skepticism about private industry's willingness or ability to undertake this investment without a resurgence in internal cash flow. The two key related uncertainties are:

- To what extent will corporations undertake massive new plant and equipment spending?
- To what extent can whatever investment is undertaken be financed internally, by the cash available from retained earnings?

Rather than choose one particular point estimate for each of the key uncertainties, we shall specify a set of three possible scenarios which bracket the range of probable outcomes. The three alternative scenarios are described briefly below.

Scenario 1 is called the High Investment, Depressed Internal Funds Scenario. In this scenario, it is assumed that plant and equipment spending will climb to historically high levels, in order to satisfy many of the needs and requirements described above.[1] It is also assumed that the recent difficulties of corporations in realizing returns on their existing assets will continue, so that retained earnings and internal cash flows will remain depressed. This scenario presumes the trends of the last several credit cycles toward expanding corporate financial needs and contracting internally generated funds will continue. This scenario is perhaps most consistent with a future economy that is expanding rather rapidly and that is beset with continuing inflation and depressed corporate profits.

Scenario 2 is the High Investment, Moderate Internal Funds Scenario. In this scenario, it is again assumed that plant and equipment spending will climb to the same historically high levels assumed in Scenario 1, in order to satisfy many of the needs and requirements described above. But it is also assumed that corporate retained earnings and internal funds will expand, rebounding to the same average fraction of GNP they attained in the 1950s and early 1960s. Thus, a substantial faction of corporate investment will be financed internally. This scenario is most consistent with a future economy that is expanding, perhaps rapidly, but without the intense inflationary pressure of recent years. Thus corporations will be able to increase and maintain profit margins.

---

[1] *In particular, it is assumed that corporate plant and equipment spending climbs to 8.8 percent of GNP, averaged over the next credit cycle. This is a full 1 percent of GNP higher than the experience of the most recent credit cycles. Thus, relative to the past, plant and equipment spending is assumed to expand considerably. While it is expressed in somewhat different terms, this assumed plant and equipment spending is approximately consistent with the assumptions of several other recent studies. See, for example: Bosworth, Duesenberry, and Carron, Capital Needs in the Seventies, Washington: Brookings, 1974; and New York Stock Exchange, The Need for Equity Capital, February, 1975.*

Scenario 3 is the Moderate Investment, Moderate Funds Scenario. For this scenario it is assumed that plant and equipment spending declines somewhat from recent levels to a new level similar to that of the 1950s and early 1960s. Within this moderately declining total, several categories of capital spending will undoubtedly continue to increase, specifically energy-related investment, pollution control expenditures, and capacity additions within some of the basic materials industries. Most other capital spending will decrease, however. As in Scenario 2, it is assumed that corporate retained earnings and internal funds will rebound to the average levels they attained in the 1950s and early 1960s. Therefore, an increasing supply of funds is generated internally to finance what turns out to be only a moderate rate of investment, and external funds requirements are reduced. This scenario is most consistent with a future economy which is expanding at a slow or moderate rate with lower inflationary pressures, and in which corporate managers expand their productive capacity only after they have increased their returns from existing capacity.

As suggested in the brief scenario descriptions above, plant and equipment spending and adjusted retained earnings are the key variables for which assumptions have been made. The other sources and uses of funds have been chosen to be consistent with past levels, but are adjusted as necessary to be compatible with the assumed conditions in the scenarios. Specifically, corporate investment in residential construction, financial assets, and the discrepancies between them are equal in all three scenarios, and consistent with earlier credit cycles. Depreciation and inventories are higher in the high investment scenarios, to reflect the effects of the bulge in plant and equipment spending on economic activity, and, later, depreciation. The detailed assumptions are shown in Exhibit IV-9.

The table below summarizes the sources and uses of funds for non-financial business corporations which are likely to occur in Scenarios 1, 2, and 3. All estimates are shown as a percentage of GNP averaged over a prospective credit cycle.

COMPARISON OF THREE ALTERNATIVE SCENARIOS WITH FIVE PREVIOUS CREDIT CYCLES
(percent of GNP)

	Plant & Equipment Spending	Adjusted Retained Earnings	Net External Funds Required
Credit Cycle 1 1954:3 to 1958:1	6.9	2.5	2.4
Credit Cycle 2 1958:2 to 1960:4	6.5	2.2	2.1
Credit Cycle 3 1960:1 to 1967:1	7.0	2.6	2.5
Credit Cycle 4 1967:2 to 1970:3	7.8	1.6	3.2
Credit Cycle 5 1970:4 to 1974:4	7.7	1.0	4.3
Scenario 1	8.8	1.3	5.0
Scenario 2	8.8	2.5	3.8
Scenario 3	7.2	2.5	2.4

As the final column in the table above and the bottom row in Exhibit IV-9 indicate, there is a wide range of possible net external funds requirements across the three scenarios. In Scenario 1, the high investment, depressed retained earnings scenario, the net external funds required increase to a new high of 5.0 percent of GNP, a figure larger than in the 1970-1974 credit cycle and substantially larger than in earlier cycles. In Scenario 2, where profits are assumed to be higher than in 1, the net external funds requirements are 3.8 percent of GNP, somewhat lower than in the most recent credit cycle, but still high by historical standards. Finally, in Scenario 3, where investment is assumed to be lower than in 2, the net external funds required drop to 2.4 percent of GNP, substantially less than in recent years, and roughly comparable to requirements in the three earlier credit cycles.

These net external funds required are a measure of the extent to which non-financial corporations will have to rely upon financial institutions and markets for funding; and, therefore, they are a measure of the pressure corporations will exert on financial markets. One interpretation of these results suggests that if the rather high investment rates anticipated by many economists and reflected in Scenarios 1 and 2 actually occur, then corporations will exert considerable pressure on the capital markets. If corporate internal sources of funds remain depressed, then this pressure will be very high in comparison with all recent experience. Moreover, even if internal sources recover, the corporate demand for funds will still be quite high, surpassed only by the levels of 1970-1974. Only if high rates of investment do not occur and internal funds recover (as in Scenario 3) will the pressure of corporate net external funds requirements slip back to the levels of earlier years.

Exhibit IV-11 translates the estimates of financing needs in all three scenarios from a percentage of GNP to yearly dollar estimates. These figures will be compared directly with electric utility financing requirements in Chapter 5.

CORPORATE EXTERNAL NEEDS IN COMPETITION WITH OTHER SECTORS OF THE ECONOMY

The external financial needs of corporations are only one of several important financial needs in the economy.

In addition, the capital projects of state and local governments are often financed through "municipal" borrowing. Furthermore, when the federal government experiences a budget deficit, it is financed through federal borrowing. Finally, the household sector borrows in the form of both home mortgages and consumer credit. These various demands must compete for the net supply of funds, most of which are provided through financial assets acquired by the household sector.

Because the household sector is the source of most of the supply drawn on by other economic sectors, the analysis in this section will focus upon the "net financial investment" of the household sector, where the net financial investment of households is defined as the net increase in financial assets (the total supply of financing) minus the net increase in household borrowing. By subtracting household borrowing, the analysis excludes amounts which some households supply to other households. Thus, the focus is on the net financing provided by households as a sector to all other economic sectors. For all practical purposes, then, the net financial demands for funds of the corporate and government sectors must be financed through the supply of funds provided by the net financial investment of households.

There are several minor problems with the closed financial system suggested above. First of all, there are a number of minor economic sectors excluded from the analysis, specifically non-corporate businesses and farms. Fortunately, these sectors are small enough that their omission should cause no real problems. Secondly, the corporate sector, state and local governments, or the federal government actually could have negative net external financial needs; that is, they could on balance retire more debt than they raise. In recent years, however, the corporate sector and state and local governments as a group have always been borrowers.

A final element excluded from the foregoing analysis is international sources of funds. When the balance of payments on current account of the U.S. is deficit, then foreigners will be supplying net financial investments to the U.S., and vice versa. In the 1970-1974 period, for example, the U.S. did experience several periods of substantial deficits, and the rest of the world did provide some financing. Currently, however, the U.S. is enjoying substantial balance of payments surpluses, so that the funds provided by the rest of the world are actually negative. In the current era of floating exchange rates, the most reasonable forecast of future balance of payments is that, on average, they will probably be zero. Thus, the most reasonable forecast of net financial investment by the rest of the world in the U.S. is that it will, on average, be zero. If so, the financial system of the U.S. can be viewed in isolation from the rest of the world. The external financial needs of the U.S. corporations and governments must be equal to the net financial investment supplied by U.S. households for this to be true.

Because corporate and governmental financial needs must be supplied by households, the final link in the analysis is to investigate the savings behavior of households. For the purposes of this analysis, the "net saving" of households is defined as the sum of their accumulation of net financial investment (financial assets minus financial liabilities) plus the net increase in residential construction (the dollar value of new houses purchased by households minus the depreciation of the existing housing stock).

Exhibit IV-10 documents the savings behavior of households over the five recent credit cycles used in Chapter 1. The data suggest that the rate of households' net savings (as a percent of GNP) has fluctuated between 5.4 and 6.6 percent. Numerous other long-term studies of household savings behavior in recent decades confirm that net savings rates fluctuate approximately in this range, with no discernible long-term secular trend.[2,3] On the other hand, there has been a drastic shift in the composition of net household savings across these five credit cycles. In the credit cycles of the 1950s, the net saving of households was dominated by the increase in net residential construction. In the later credit cycles, however, new home construction became a much less important form of saving, and net financial investment became the dominant component of saving. Needless to say, most of this net financial investment was used to fund the growing net external financing requirements of business in these periods. The increased funds requirements in the corporate sector may well have "crowded out" additional housing in these years.

THE SUPPLY AND DEMAND FOR FUNDS IN THREE ALTERNATIVE SCENARIOS

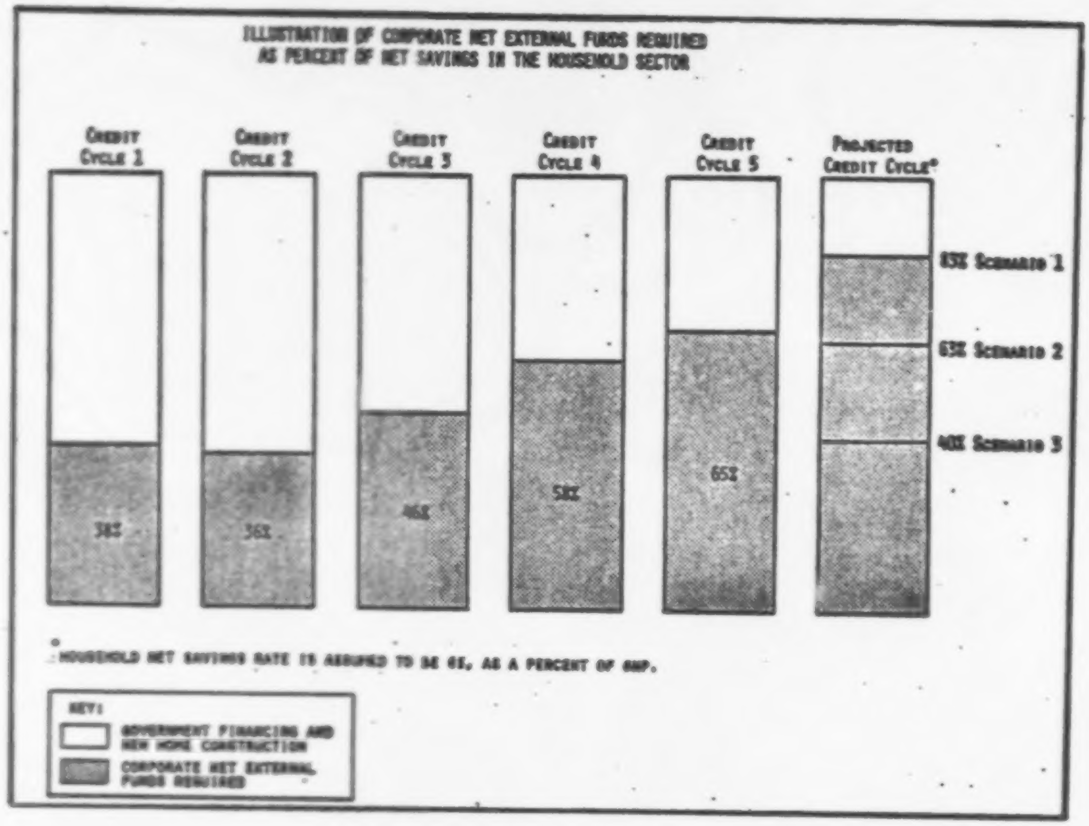
Because of the relatively steady behavior of households' net saving in recent cycles, it is possible to make some initial observations about the capacity of the U.S. financial system to fund various future corporate needs. It is assumed that households in future credit cycles will save in the range of 5.5 to 6.5 percent of GNP, about the range over the last five credit cycles. These net savings must then be divided between net investment in homes and net financial investment. The latter is, in turn, divided into

---

[2] *The exception to this is the unusual savings rate in times of extreme economic or political conditions; e.g., World War II and the Great Depression.*

[3] *See, for example, Friedman, M., A Theory of the Consumption Function, Princeton University Press, 1957.*

funds for corporate, state and local government, and federal government financial needs. The table below shows the magnitude of corporate external requirements, in relation to households' net saving, assuming the latter to be 6 percent of GNP.



Although the foregoing table may suggest that housing and governmental financing are a residual, this is not the case. The governmental sector is a strong competitor for funds. Therefore, a brief review of the historical and possible future levels of the other demands for funds must be analyzed. As Exhibit IV-10 suggests, the net increase in residential construction has fluctuated from 1.3 to 1.9 percent of GNP in recent credit cycles, down sharply from the 1950s. While demographic and economic factors suggest that the construction of new housing may remain relatively depressed, it is difficult to imagine its falling below this range (1.3 to 1.7 percent) without seriously endangering national housing goals. From a public policy perspective, it would be most desirable to maintain enough financial capacity to fund new housing in the vicinity of at least 1.5 percent of GNP.

It is true that, in past periods of credit tightness, the response of households has, in effect, been to shift funds from housing to corporations. In the late stages of each of the recent credit cycles, households have increased substantially their purchases of corporate securities, either directly through brokers or indirectly through mutual funds and related vehicles. The process has involved a transfer of household funds to high-yielding corporate securities and from the deposit institutions that invest primarily or importantly in mortgages. This shift of funds from deposits to direct purchases, called disintermediation, has occurred in each of the recent credit crunches. The magnitude of the diversion of funds from mortgages may be smaller in the future than in the past.

In recent years, several large and growing off-budget federal agencies, the Federal National Mortgage Association (FNMA) and the Federal Home Loan Mortgage Corporation (FHLMC), have been established to supplement the flow of money to residential mortgages. These federal agencies are now very effective competitors for funds in the federal agency securities market and are likely in the future to step up their activities in periods of credit stringency so that the flow of funds to the mortgage markets is somewhat less volatile. If so, the emergence of these agencies will clearly make it more difficult for corporations to bid funds away from the mortgage market.

The external financial needs of state and local governments have accounted for a rather steady but important amount of financing in recent years. Averaged over recent credit cycles, the net external financing of state and local govenrments (that is, the total increase in external financing minus the increase in financial assets held) has fluctuated between 0.6 and 0.8 percent of GNP. Despite this stable history, predictions of future municipal financing needs are extraordinarily difficult. An abatement of the basic needs of municipalities seems unlikely. However, the historical cyclical behavior of state and local governments suggests they are sensitive to interest rate savings, curtailing their financing in times of high needs in other sectors. Thus, to the extent that future increases in the needs of other sectors over a full cycle manifest themselves in increases in interest rates, municipal borrowers may be "crowded out" in a high corporate investment economy.

The final large financial demand, that of the federal government, has fluctuated widely from year to year. In the credit cycles of the 1950s, the net external financial needs of the federal government were approximately zero, because of the balanced budget philosophy of those years. In the most recent credit cycle, however, these net external financing needs exceeded 1 percent of GNP. Again predictions of the net effect of federal taxing and expenditure decisions are perilous. It seems unreasonable, however, not to consider deficits as a strong future possibility.

With this background on possible future levels of financing needs in the housing and governmental sectors, the financial implications of the three corporate scenarios can be set in perspective. Under Scenario 1, where corporations continue to expand their rate of investment without a recovery in internal funds, the external financing needs of corporations would require virtually all of the net savings of households, leaving very little available for new housing, state and local governments, and the federal government.[4] This scenario is indeed a "capital shortage" scenario, where considerable strains would almost certainly be placed upon the financial system. Indeed, Scenario 1 is probably a workable projection only if the government sector as a whole actually supplies funds to the system. Otherwise, in order to bring the system to equilibrium, some combination of new housing, small business, state and local governments, and financially weak larger corporations would be "crowded out" in the competition for funds.

Even under Scenario 2, the financial needs of the corporate sector would appear to be quite large in relation to potentially available funds. Over 60 percent of households' net savings would be required to finance corporate needs, leaving only a modest amount for housing and governments. Presumably, if the federal government averaged zero financial needs over the future credit cycle, then Scenario 2 could be realized with a minimum of financial strain. If, however, the federal government managed its affairs so as to produce a sizeable net deficit averaged over the credit cycle, a possibility which most political observers find far more plausible, then the combined financial needs of the federal government and the corporate sector would still "crowd out" some potential borrowers.

---

[4] *All of this assumes that the Federal Reserve chooses to expand the supply of money and bank credit at rates consistent with economic growth. In the short run, of course, the Federal Reserve theoretically could choose to supply enormous amounts of money and credit through the banks. The result in the long run would be enormous inflation. We are assuming implicitly an "appropriate" monetary policy in our analysis; that is, a monetary policy which is tied to real economic growth.*

Scenario 3 is the most encouraging scenario, at least from the perspective of the supply and demand for funds. In Scenario 3, the external financing needs of corporations are modest in relation to the available supply of households' net savings. Thus, substantial funds would be available for new housing, state and local governments, and the federal government.

VARIATIONS WITHIN A CREDIT CYCLE

The projections above are all stated in terms of the supply and demand for funds as a percent of GNP, averaged across a prospective credit cycle. As pointed out in Chapter 2, however, there are substantial fluctuations in the demands for credit within a cycle. If, on average, these needs are large, then a typical credit cycle could be described as a series of subperiods, during some of which funds are not readily available. During the subperiod of peak corporate financial needs, there will be particularly great strains on the financial system. In Scenario 1, and probably even in Scenario 2, this will be a time when the corporate financial needs will exceed substantially the normal sources of supply.

CONCLUSIONS

The preceding discussion considers future financial flows of funds through a presentation of three alternative projections of corporate external needs. The three alternative scenarios present drastically different assessments of the potential availability of funds. If Scenario 1 occurs, there will almost certainly be a substantial "capital shortage," complete with the crowding out of weaker economic sectors. If Scenario 2 occurs, the external needs of corporations could probably be financed, along with moderate new housing and state and local government projects, as long as the federal government did not run at a substantial deficit. If Scenario 3 occurs, corporate external needs could be easily financed, leaving substantial funds available for other uses.

These three scenarios were constructed to bracket the range of probable outcomes. As of early 1976, the moderate investment projection of Scenario 3 seems more likely than Scenario 2 and much more likely than Scenario 1. The current level of capacity utilization and of business concerns about profitless capacity expansion tend to suggest an attention to profits and a constraint on investment for at least the next several years. Thus, there is a good chance that future corporate financial needs can be met without placing undue strains on the financial system. A more pessimistic appraisal might emphasize the chance that corporate financial needs will be very large relative to the potential supply of funds, placing substantial strains on the financial system. While the pessimistic scenarios are perhaps ones having a relatively low probability, they cannot be discounted completely. Over the entire 1975-1985 decade, however, the high investment-low profit assumptions in Scenario 1 seem inconsistent with recent corporate behavior, and thus much less probable than the assumptions of Scenario 2.

CHAPTER 4

INVESTOR-OWNED ELECTRIC UTILITY FINANCIAL RESULTS AND FINANCING 1960-1975

Volume I of this report traced the events that occurred in the late 1960s that changed the nature of the electric utility industry, together with the impact of these changes on the operating results of investor-owned electric utilities. This chapter outlines the financial results over this same period.

Briefly, the developments and trends discussed earlier--credit crunches, inflation, equipment shortages, the environmental movement, and fuel cost increases--caused the industry to suffer a number of financing difficulties in 1973 and 1974 and to leave it still in an uncomfortable--if not precarious--financial condition in early 1976. To highlight this situation, this chapter first will describe the industry's financial results and access to capital in the 1960-1965 period, then will contrast the conditions existing in the 1966-1973 time period. Finally, the chapter concludes with a review of 1974 performance and available data on 1975 results.

1960-1965: GROWTH AND PROSPERITY

The decreasing costs of electric power, the stable increases of electricity consumption, the stable or declining costs of new capacity, and the good reception for utility securities in the capital markets all combined to result in a rapid growth in earnings for the industry. Because of regulatory lags, cost reductions often led rate reductions by a substantial time span, with the result that the benefits of these cost reductions accrued in part to the stockholders of electric utilities. As a result, net income increased each year, from $1.6 billion in 1960 to $2.4 billion in 1965, an average annual increase of 7.4 percent (see Exhibit IV-12). Moreover, the industry's return on equity improved significantly, from 11.6 percent to 12.8 percent (Exhibit IV-13).

Despite the industry's large and increasing net income, retained earnings met only a small fraction of the industry's total need for funds from 1960 to 1965. The product of the industry's growth rate and capital intensiveness (Exhibit IV-14 shows that gross plant and equipment was about 4.5 times revenues) resulted in yearly capital expenditures ranging from about $3.2 to $4.0 billion in the early 1960s or 6.7 to 7.5 percent of each year's initial total assets (see Exhibit IV-15). Together with modest yearly changes in net working capital requirements, these capital expenditures resulted in the yearly funds needs detailed in column 11 of Exhibit IV-16. Retained earnings supplied only an average of about 16 percent of the industry's 1960-1965 funds needs (Exhibit IV-16, page 2). This relatively small equity fraction was the product of three factors: common equity constituted less than 40 percent of the industry's total capital (see Exhibits IV-17 and IV-18 for detailed financial structure data); return on equity averaged only about 12 percent (Exhibit IV-13); and nearly two-thirds of earnings was paid out as dividends (Exhibit IV-13). As a result, yearly retained earnings in relation to initial common equity averaged only about 4.0 percent[1] and relative to initial capitalization averaged only about 1.5 percent.[2] This latter figure contrasts with yearly capital expenditures averaging about 7 percent of initial total assets and 8 percent of initial capitalization, because long-term capital accounted for about 88 percent of total liabilities and capital.

---

[1] *4.0 percent = 12.0 percent x (1.00 - .663), where .663 is the average dividend payout as a fraction of earnings.*

Depreciation, amortization, and deferred taxes, i.e., non-cash charges against income, were an important source of funds from 1960 to 1965 (depreciation and amortization constituting about 37 percent of total funds needs, and deferrals about 4 percent), but the industry still relied heavily on external sources. Although it was trending downward slightly during the early 1960s, 44 percent of the industry's total funds needs were met by external sources (Exhibit IV-16b).

Despite its heavy reliance on external financing, the industry found it extremely easy to issue common equity for cash. As is evidenced by common equity market prices generally above book value--in many instances more than 2.0 times book value (Exhibit IV-19)--the returns on equity allowed by regulators during this period were often far above the minimum rates of return demanded by the suppliers of equity. The existence of this excess return, i.e., the rate of return allowed versus the return available elsewhere in the capital markets on investments of comparable risk, meant that the more equity issued by a utility, the better off its shareholders--if not customers--tended to be.

---

[2] *1.5 percent = 4.0 percent x .377, where .377 is the average ratio of common equity to total capitalization.*

Although this economic logic was perhaps only dimly perceived by many investors and industry managers, the 1960-1965 period was one in which the industry employed a high volume of common equity issues (see Exhibit IV-20), and thereby increased its common equity to capital ratios slightly (see Exhibit IV-17). The excess return allowed by regulators also contributed to a strong earnings per share growth pattern (Exhibit IV-13), about 7.5 percent growth per year. As is discussed in Appendix A, the issuance of common stock at significant premiums above book value tends to boost the rate of earnings per share growth above the "normal" case where growth is equal to the rate of return on equity times the fraction of earnings retained, i.e., the complement of the dividend payout ratio.[3]

Although the industry did slightly decrease the proportions of debt and preferred stock in its capital structure--from 52.8 percent debt and 10.7 percent preferred in 1960 to 51.5 percent debt and 9.5 percent preferred in 1965--the industry's issuance of debt and preferred stock during this period was nonethless very large, as is shown in Exhibit IV-16. These issues were well received by conservative institutional investors and a few individuals. The industry's stability--in earnings record and future prospects--was one point in its favor. Secondly, given that the industry's rate of return on common equity was very high compared to prevailing interest and preferred dividend rates (Exhibit IV-21), its interest and preferred dividend expenses were well covered by earnings (Exhibit IV-22) despite an uptrend in its average cost of debt (Exhibit IV-23). Thus, the industry easily met a major portion of its total capitalization needs via the issuance of long-term debt and preferred stock.

---

[3] *Assuming a 12 percent return on common equity and a 70 percent dividend payout ratio, yearly earnings per share growth--either with no new stock issues or with issues sold at book value--would be 3.6 percent, where:* $3.6 = 12(1 - .70)$.

In summary, the early 1960s were prosperous years for utility managers and investors. Changes were in the wind, however, and the impact of these changes on the industry's financial results and financing capabilities is discussed in the next section.

1966-1973: GROWTH WITHOUT PROSPERITY

Volume I of the report indicated that the consumption of energy grew at an average annual rate of 7.1 percent in the 1966-1973 period, while the growth in peak demand grew at an 8.1 percent rate in the same period. The combined effect of the industry's meeting these demand requirements while experiencing a more than doubling in the cost of a kilowatt of installed capacity resulted in an increase in capital expenditures from $4.0 billion in 1965 to $14.9 billion in 1973 (Exhibit IV-15). This represents an increase in capital expenditures relative to initial assets from 7.5 percent to 13.5 percent.

In addition, by the end of 1973, because of rapidly escalating fuel and other costs and slowdowns in collections of accounts receivable, the industry began to require significant amounts of funds for increasing accounts receivable and inventories. (The industry's total funds needs are shown in column 11 of Exhibit IV-16.)

Thus, by 1973 the ability to finance continued growth had become a major concern to the electric utility industry. The remainder of this section discusses the internal sources of funds available to the industry, then external sources, and finally the competition for funds in the capital markets.

Internal Sources of Funds

Caught between rising capital costs and an increasing resistance to rate increases on the part of consumers and regulators, the industry's earnings available for common stock managed to grow from $2.3 billion in 1966 to $3.9 billion in 1973 (Exhibit IV-13), but this was a rate of growth well below that of the industry's total common equity base (Exhibit IV-17). Thus, the industry's return on equity dropped sharply from 13.0 percent in 1966 to under 12 percent in 1970 through 1973 (Exhibit IV-13). Given continued high payout ratios, retained earnings dropped sharply compared to increasing total funds needs, from an average of 15.4 percent in the early 1960s to an average of 8.2 percent in the early 1970s (Exhibit IV-16).

An additional problem was that an increasing percentage of reported earnings took the form of a non-cash credit to income, the allowance for funds used during construction (AFDC). As shown in Exhibit IV-24, AFDC has grown from under 5 percent of income available for common stock in 1966 to over 31 percent in 1973. Because AFDC contributes to earnings without contributing to cash flows, its rapid increase has caused a number of investors to question the quality of earnings in recent years.

A further factor contributing to the perceived decline in earnings quality from 1966 to 1973 is the fact that the capacity being depreciated typically had been constructed at a cost substantially below the then current replacement cost for a like unit of capacity, thereby causing an overstatement of earnings in real terms. Moreover, because about 40 percent of the industry's assets were in regulatory jurisdictions requiring flow-through accounting, much of the cash flow benefits of accelerated depreciation and investment tax credits were used to reduce the rates charged current electric utility consumers rather than to reduce the industry's external financing requirements and the rates charged future customers.

These latter factors caused depreciation and deferred taxes to decline in importance in relation to total funds used, even though depreciation remained much larger than retained earnings as a source of funds. As shown in Exhibit IV-16, depreciation declined from about 37 percent of funds needs in 1960-1965 to under 22 percent in the early 1970s.

External Sources of Funds

Because the industry's need for funds in the 1966-1973 period grew more rapidly than its internal sources, its reliance on external financing went up dramatically. As shown in Exhibit IV-16b, external funds as a percent of total needs averaged less than 45 percent in the early 1960s and were actually trending downward. The ratio shot up above 60 percent in the late 1960s and to average levels near 70 percent in the early 1970s.

Meeting these external financing needs was a formidable task. A combination of adverse earnings trends peculiar to the industry, increasing levels of inflation and hence nominal rates of return demanded by investors, an increase in the demands for financing by other corporate sectors, and the enormous scale of the industry's needs relative to total corporate financing had, by the end of 1973, severely constrained the ability and willingness of many utilities to meet the terms demanded in the U.S. capital markets.

In the case of investor-owned utilities, a first problem was that declining interest coverage ratios greatly diminished the industry's ease of access to debt financing (Exhibit IV-22). These declining coverage ratios stemmed primarily from two causes. First, utilities had to issue new debt at interest rates of 8 percent or more, or substantially above embedded rates (see Exhibits IV-21 and IV-23). Secondly, coverages were hurt by the industry's decreasing return on equity (Exhibit IV-13). Capital structure ratios remained relatively constant (Exhibit IV-17), and thus played little part in the coverage downtrend.

The industry averages mentioned above obscure important differences between individual electric utility systems. In the averages are a number of utilities with coverage ratios near 2.0 times. The 2.0 times coverage ratio doubtless had important psychological implications for investors, but even more concretely, it was important because a 2.0 times coverage requirement was stipulated in the indentures of most first mortgage bonds. When coverages including the interest on the prospective issue fell below this level, most utility systems were precluded from issuing additional debt securities ranking equally in security with their first mortgage bonds and many were precluded from any additional debt. The coverage ratios described above also may obscure the fact that many bond indentures limited the extent to which the allowance for funds used during construction could be included in earnings for the purpose of calculating interest coverage. Some indentures altogether excluded AFDC and other income from consideration in the calculation of coverage ratios.

Some utilities unable to issue first mortgage bonds could still add junior long-term debt, such as second mortgage bonds or debentures. The amounts of such issues were also typically controlled by the terms either of the system bonds or of its preferred stock. Moreover, even if allowed, these junior securities historically sold at spreads of roughly 25 basis points, i.e., 0.25 percent, above the senior bonds of the same company. Furthermore, for a company in earnings coverage trouble, these junior securities might have been given such a low rating as to necessitate an even larger yield spread than had been true historically. In fact, ratings below a Moody's A might have resulted in a system's having to issue its securities to other than the usual purchasers of utility debt obligations, which investors tended to be interested only in high-quality obligations. In part because of the constraints on and costs of long-term debt, in part because of a hope that later issues of long-term debt or equity could be made on more favorable terms, the industry increased its use of short-term debt (commercial paper and bank loans) from under $1 billion in the early 1960s to nearly $4 billion in 1973 and issued significant amounts of intermediate-term (5-year to 10-year) notes (see Exhibit IV-18).

Preferred stock remained a viable financing alternative for the industry through the 1966-1973 period. In fact, as shown in Exhibit IV-17, the proportion of preferred stock in the industry's capital structure grew slightly, to 12.1 percent in 1973. As in the case of debt, however, these new issues went out at increasingly high yields.

Despite the problems attendant to both debt and preferred stock financing during the 1966-1973 period, common stock financing was on balance even less attractive to the industry, so that the percentage of common equity in the industry's capital structure dropped from 38.2 percent in 1966 to just over 35 percent in the 1970-1973 period. The industry's fundamental problem was that its return on equity declined from 13.0 percent in 1966 to 11.7 percent in 1973, while the returns demanded by investors increased substantially.

This increased rate of return requirement was primarily due to two reasons. The first was inflation. As investors sought to preserve roughly constant real returns on their investments in securities, the nominal required rates of return on securities in any given risk class were driven up by amounts corresponding to the rate of inflation. Secondly, because of increasing uncertainty about the political and regulatory environment in which the industry operated, the investment community appeared to be assigning a higher degree of risk to the electric utility industry and hence to be demanding a higher real rate of return than it had in the past.

As a result of the relative changes in actual and demanded rates of return, the industry's stock price relative to book value dropped from an average well over 2.0 in the 1960-1966 period to 0.79 in 1973 (Exhibit IV-19). Similarly, the industry's price to earnings ratio dropped from about 20 in the early 1960s to 8.1 in 1973.

As detailed in Appendix A, once the industry's market-to-book ratio fell below 1.0, the issuance of common stock *per se* tended to depress future earnings per share growth, which decline in earnings per share growth--when anticipated by investors--led to a further reduction in the industry's market price. Thus, the phenomenon which had helped fuel the industry's spectacular earnings per share performance of the early- and mid-1960s was, by 1973, working in reverse. As a consequence, between 1966 and 1973, the increase in the number of shares of common stock outstanding had been almost as great as the growth in net income in the industry. The growth rate in earnings per share of common stock was just over 3.1 percent between 1966 and 1973. This compares with an average increase in net income of 8.2 percent annually during the same period (Exhibit IV-13).

Competitive Demands for Funds

To set the foregoing external financing history in context, it might be noted again that each of the last three credit cycles has shown a successively larger total demand for capital, highlighted particularly by long-term financing needs of corporations. These corporate financing needs have, in fact, grown to be quite large in comparison to the traditional supplies of long-term institutional capital, resulting in the emergence of individuals as new investors in corporate debt securities. What is important for our purposes is the the demand for electric utility financing has increased even more rapidly than total corporate financing needs in the last 14 years, so that it has been an expanding fraction of an expanding corporate demand for financing.

While the electric utility industry's share of capital expenditures by all non-financial corporations rose from an average of under 9 percent in the early 1960s to nearly 15 percent in the 1970s (Exhibit IV-25), the industry came to represent an even larger share of total non-financial business financing. The industry's share increased from an average of about 12 percent in 1961-1966, to 14 percent in 1967-1969, and to about 18 percent in 1970-1974 (Exhibit IV-26).

The electric utility industry has historically accounted for an even higher percentage of total corporate equity financing than of total corporate financing. As shown in Exhibit IV-26, the industry has accounted for about 40 percent of net equity financing in the early 1960s, about 50 percent in the late 1960s, and about 40 percent from 1970 to 1973. As shown in Exhibit IV-27, the industry's share of the gross equity financing of the total private sector (including financial intermediaries) is smaller than its share of net financing, but shows a strong secular uptrend from the early 1960s to the early 1970s, averaging nearly 29 percent in the 1970-1974 period.

There is considerable cyclical variability in electric utilities' share of total financing due to sizable fluctuations in financing by other corporations. Electric utilities are among the few industries that issue new common and preferred stock throughout a business cycle. Consequently, in years when total corporate uses of equity are low, the electric utility share can be quite large, indeed. In 1974, for example, investor-owned electric utilities accounted for 93 percent of all new equity financing, a huge jump from the already high 43 percent level achieved in the 1970-1973 period.

Because total corporate debt financing is less volatile than total corporate equity financing, the electric utility share of long-term debt and total long-term financing is more stable than the equity ratios. From 1970 to 1973, electric utilities accounted for 19 percent of new long-term debt and 24 percent of all long-term financing. In 1974 the electric utility share jumped to 26 percent of long-term debt and 34 percent of all long-term financing.

The increasing credit demands of electric utilities and other non-financial businesses has led to increased competition in the search for funds. Moreover, the long lead times required for building electric generating capacity and the industry's traditional objective of meeting all demands have meant that utilities have been essentially unable to tailor their uses of funds to capital market conditions. Thus, the recent decline in the quality of the industry's securities has left it increasingly exposed to cyclical variations within the credit markets and, by 1973, the industry seemed clearly to be feeling the effects of the increasingly severe competition for available capital.

1974: FINANCIAL NADIR?

The wholesale cutbacks announced in capital expansion plans during 1974 affected results in that year very little. The momentum of the electric utility industry's plant and equipment programs and high rates of cost inflation combined to result in 1974 capital expenditures that reached approximately $16.4 billion--up $1.5 billion over the year before (Exhibit IV-25). In addition, the need for funds associated with rapid increases in the industry's accounts receivables and fuels inventories reached nearly $4.5 billion.

Due largely to the more or less automatic flow-through of fuel cost increases to consumers--but also to $2.2 billion in rate increases--the industry's revenues increased by 23.6 percent to $39.1 billion in 1974. These rate increases, however, fell short of matching increases in costs other than fuel, and two very significant financial measures deteriorated:

- Net income available for common shareholders declined 2 percent in 1974, (Exhibit IV-13), and
- Return on equity declined to 11.0 percent from a level of 11.7 percent the year before, this 1974 figure being the lowest level in over 15 years (Exhibit IV-13).

And not only did the level of earnings decline; the quality of 1974 earnings deteriorated even further. The allowance for funds used during construction--a non-cash credit to income--grew again as a percent of income available for common shareholders. From 31.8 percent of income in 1973, AFDC increased to 38.4 percent of income in 1974. (See Exhibit IV-24.)

The industry's imbalance between funds needs and internal sources resulted in record-high external needs in 1974. These needs totaled $14.8 billion (Exhibit IV-26).

The dismal earnings performance of most companies in the industry, particularly relative to the inflation-bloated rates of return demanded by investors in equity and debt securities, caused the industry to have enormous difficulties in raising external capital in 1974. Consolidated Edison's infamous dividend cut of April 1974 and its forced transfer of generating facilities to a public agency because of an inability to finance them contributed in no small way to investors' concerns.

As a result of the lowered earnings, higher interest costs, and some shift in the capital structure toward debt, interest coverage for the industry declined to roughly 2.2 in 1974 (Exhibit IV-22). This decline continued the steady deterioration from a 5.0 interest coverage in 1966. Most observers agree that an interest coverage close to 2.0 is extremely dangerous and could result in the debt markets being substantially closed to a large number of companies. In fact, a number of companies were constrained in 1974 from issuing long-term debt by inadequate interest coverage ratios. A number of others found that their falling coverages were leading to an unprecedented number of reductions in bond quality ratings (see Exhibit IV-28) and consequently higher interest costs. Even those bonds retaining high quality ratings had to come to market with record-high coupons (see Exhibit IV-29). Moreover, a large number of companies chose to issue intermediate-term notes in an attempt to avoid having to live with extraordinarily high rates of interest over the 30-year life of mortgage bonds.

In spite of these difficulties with interest coverage, the industry was nonetheless able to increase its net debt financing by $10.3 billion in 1974. In part because of necessity, the short-term debt portion of this total grew a record amount in 1974--almost $2.6 billion (Exhibit IV-18).

Preferred stock financing grew in 1974 to $1.8 billion, but new common stock issues fell to $ 2.0 billion, causing a further decline in the industry's equity to capitalization ratio. The industry's inability or unwillingness to issue enough common stock to maintain capitalization ratios (much less to maintain interest coverage ratios) is directly attributable to allowed rates of return on equity far below the rates demanded by investors. This disparity manifested itself in a market-to-book ratio of 0.52 and in a price to earnings ratio of 5.4 in June 1974.

Although the industry's public announcements of cancellations or deferrals of capital expenditure plans typically attributed the change to altered estimates of future growth and capacity requirements, some cancellations were acknowledged to be related to financing difficulties and some industry observers feared that other changes in capacity programs were brought about because of the strained financial position of some companies in the industry. Since a major portion of the industry's nuclear plant programs were delayed or cancelled, a particular fear in some quarters was that capital constrained companies were being led to make tradeoffs between capital and operating costs that, in the long run, would prove detrimental to consumers. This remains a question open to debate. If the industry's allowed rate of return long remained at as large a discount from investors' demands as it was in 1974--in spite of very high current levels of reserve margins--it appears apparent that consumers would eventually suffer the economic consequences.

1975

As mentioned in Volume I, complete data for 1975 are not yet available, but informed estimates are available which provide an indication of what the financial results and financing situation may have been for the industry. Highlights of the results and financing situation are presented below:

- Capital expenditures for 1975 amounted to $16.8 billion, up only marginally from the year before.
- Net external financing was $10.2 billion, or 61 percent of the total need for funds, including:
  - --Common stock of $3.4 billion
  - --Preferred stock of $2.1 billion
  - --Debt of $4.7 billion, with an additional $3.0 billion refinanced.
- Revenues for 1975 probably increased about 12 percent to $44.3 billion, the largest portion of the increase coming once again from fuel cost pass-throughs.
- Earnings for 1975 improved over the depressed levels of the year before, with
  - --Total earnings up about 10 percent
  - --Earnings per share up about 6.5 percent.
- Returns on equity increased slightly, to about 11.3 percent.
- Interest coverage ratios improved significantly, from 2.2 times in 1974 to about 2.5 times in 1975.

In sum, the year 1975 was clearly an improvement over 1974 for the electric utility industry. It was not a banner year, but several encouraging signs began to emerge. First, the seriousness of the industry's difficulties led to an increasing awareness at many levels that consumers would sooner or later, and directly or indirectly, bear the costs--including capital costs--of producing electricity and that attempts to avoid passing further cost increases to already irate consumers could redound to their long-run disadvantage. Second, to the extent that demand growth trends had permanently been reduced, the industry's funds needs would abate, necessitating less external financing. Third, an increasing level of discussion concerning peak-period pricing and other fundamental revisions of traditional rate structures encouraged the hope that economically efficient price signals would contribute to diminishing the required rate of growth of capacity. Finally, inflation abated somewhat, and together with the moderate increases in returns allowed by rate commissions in 1975, resulted in a discernible increase in the real rate of return on the industry's common equity. The net result of all these encouraging trends was a major improvement by the end of 1975 in the industry's common stock prices.

CHAPTER 5

PROJECTIONS OF ELECTRIC UTILITY INDUSTRY FINANCING 1975-1985

This chapter presents an analysis of the electric utility industry's future external financing needs and its prospects for meeting those needs over the 1975-1980 and 1975-1985 periods, both before and after consideration of the air and water pollution regulations described in Volume III. The focus of this chapter is twofold. A first concern is the size of the investor-owned electric utilities' needs for funds relative to total sources of funds and to the requirements of the total non-financial corporate sector. A second concern is the financial strength of the investor-owned electric companies vis-a-vis their own interest coverage requirements and their competitors for funds in the U.S. capital markets.

THE INDUSTRY'S FINANCING REQUIREMENTS

As described in Volume II, the electric utility industry will need external financing of approximately $191.2 billion (1975 dollars) from 1975 to 1985 before consideration of federally mandated pollution control investments. As is shown in Exhibit IV-30, $155.0 billion of this total is required by investor-owned utilities; the remaining $36.2 billion represents the needs of the public segment of the industry. As is shown in Exhibit IV-30, the private industry's financing requirements are approximately $12.2 billion per year from 1975 to 1980 and $16.4 billion per year from 1981 to 1985.

As described in Volume III, the total industry's 1975-1985 financing needs will be increased by $21.9 billion, to $213.1 billion, by federal pollution control legislation. As is also shown in Exhibit IV-30, $19.3 billion of the incremental financing need and $174.3 billion of the need for both baseline and pollution control financing must be met by investor-owned companies. These private financing requirements average about $2.2 billion per year from 1975 to 1980 and $1.3 billion per year from 1981 to 1985. The yearly pattern, shown in detail in Exhibit IV-30, reflects the profile of expenditures for retrofitting existing plant capacity.

Two major factors bear upon the ability of the investor-owned segment of the industry to meet its external financing needs. As will be discussed next, one factor is the magnitude of the industry's needs for funds in relation to other corporations and to the total sources of funds. A second factor is the industry's financial strength vis-a-vis other corporations and other sectors competing for the total amounts of available funds.

INVESTOR-OWNED ELECTRIC UTILITY NEEDS VERSUS AVAILABLE FUNDS AND TOTAL CORPORATE NEEDS

Comparisons before Pollution Control Needs

Even if the investor-owned companies are projected to have interest coverage ratios and returns on equity commensurate with their bond indenture requirements and the rates of return demanded on securities of comparable risk, the magnitude of the industry's baseline financing needs raises some questions as to the industry's ability to meet these needs.

In Chapter 3, the projected net external funds requirements of all non-financial corporations were compared with projected net household savings, which savings figure was used as an estimate of the total funds available in the U.S. financial system. Exhibit IV-31 compares past and projected net external funds requirements of the investor-owned utilities with net household savings. The exhibit illustrates the fact that electric utility financing has increased steadily in size relative to total sources of funds over the past three credit cycles, from 5.5 percent of net household savings in the 1961-1967 period (Credit Cycle 3) to 11.5 percent in the 1970-1974 period (Credit Cycle 5). The exhibit also shows that, before pollution control financing, the industry's projected 1975-1985 needs will increase slightly above the record high of the last cycle, to about 12.5 percent of net household savings.

As is set out in the table below, the private electric utilities' share of future net household savings is influenced by the projected GNP growth rate and net household savings rate. The influence is moderate, however. Thus, even if GNP growth and savings rates are at the low end of most forecasters' ranges and even if utilities' financing needs do not decline with declines in GNP, the industry's needs are not markedly higher than in the most recent credit cycle.

INVESTOR-OWNED
ELECTRIC UTILITY NET EXTERNAL FUNDS RAISED*
1975-1985
(as % of net household savings)

	Net Household Savings Rate (% of GNP)		
GNP Growth Rate	5.5%	6.0%	6.5%
3.0%	14.0%	12.8%	11.8%
3.5%	13.6%	12.5%	11.5%
4.0%	13.3%	12.2%	11.2%

**assumes net external financing requirements of $155 billion from 1975 to 1985*

Depending on the scenario chosen to represent the financing needs of the entire non-financial corporate sector, the electric utility share of total corporate financing may be above or below the level of the recent past. The shares under each of the three corporate scenarios discussed in Chapter 3 are shown in the table below.

INVESTOR-OWNED ELECTRIC UTILITY
1975-1985 EXTERNAL FINANCING INCLUDING POLLUTION CONTROL
(billions of 1975 dollars)

	1971-1974	Scenario 1	Scenario 2	Scenario 3
Non-Financial Corporations	249	$1041	$789	$484
Electric Utility Financing	44	174	174	174
Percent of all Corporate Financing	18%	17%	22%	36%
Percent of Net Household Savings	11.5%	14.0%	14.0%	14.3%

If the capital needs of other non-financial corporations are as high as projected in Scenario 1 of Chapter 3, the electric utilities' share of total corporate financing from 1975 to 1985 would be 15 percent. That would be below the 18 percent share in the 1970-1974 period (Credit Cycle 5), but above earlier years. More important, because total corporate financing needs under Scenario 1 are projected to be at levels well above those of recent years, the competition for funds between the corporate sector and other sectors and therefore the competition for funds within the corporate sector would doubtless be fierce. Thus, the electric utility industry would have to demonstrate considerable financial strength merely to preserve its historical share of corporate financing.

Under Scenario 2, the lower level of total corporate external financing causes the electric utility industry's projected share to increase to 20 percent, a level only slightly above the 18 percent level of the 1970-1974 period. Under Scenario 2, however, the industry would doubtless still encounter some financing tightness because of the high level of total corporate financing.

While a moderate level of corporate investment as envisioned in Scenario 3 might suggest a lower level of electric utility investment than projected in the TBS baseline, the combination of moderate levels of corporate investment and high electric utility investment is conceivable. If this were to occur, total corporate financing would be well below the levels prevalent in most recent cycles, and even below the 1961-1966 level (see Exhibit IV-31), implying easy capital market conditions. However, the electric utility industry's share of total corporate financing would be enormous, reaching 32 percent, and perhaps implying problems of a different sort. The normal tendency of investors is to diversify their risks and therefore to be reluctant to invest a high percentage of their portfolios in any one industry. Nevertheless, if electric utility securities regained the quality image they enjoyed in the 1960s, such financing probably could be achieved.

The electric utility industry's share of total corporate long-term financing will be higher than its share of total financing in all scenarios, but by an amount that is difficult to predict. As discussed in Chapter 2, total corporate financing historically has comprised considerable short-term debt. As documented in Chapter 4, little of the total short-term debt has been attributable to utility borrowings. As a result, especially in years of cyclical low points in the long-term finanicng by other corporations, utilities have represented a large fraction of the total long-term financing by non-financing corporations. However, because other corporations seem at present to be attempting to reduce their past levels of reliance on short-term debt, their long-term financing in the future may increase as a fraction of their total financing. If so, the utilities' share of long-term financing may be below past levels, though it doubtless still will be above the utility industry's share of total financing.

Comparisons After Pollution Control Needs

The financing associated with federal pollution control represents a 17.8 percent increase in private utilities' financing requirements in the 1975-1980 period and a 12.5 percent increase in the 1975-1985 period. As discussed in the preceding section, the industry's baseline financing requirements are themselves of a major magnitude, so these percentage increases result in discernible increases in the industry's projected share of total U.S. sources of funds and of total non-financing corporate financing. Assuming net household savings of 6 percent of GNP and a real GNP growth rate of 3.5 percent, the electric utilities' needs during the 1975-1985 period would rise from 12.5 percent of net household savings before pollution control requirements to 14.0 percent after pollution control. Despite the substantial percentage increase attributable to pollution control equipment in the 1975-1980 period, the industry's external financing requirements including pollution control needs will be slightly lower, 13.8 percent, in the early subperiod than in the full 1975-1985 period. These results, together with the results for alternative GNP growth and savings rate assumptions, are shown in the table below.

INVESTOR-OWNED ELECTRIC UTILITY NET EXTERNAL FUNDS RAISED*
WITH POLLUTION CONTROL EQUIPMENT
1975-1985
(as % of net household savings)*

Net Household Savings Rate (% of GNP)

GNP Growth Rate	1975-1980			1975-1985		
	5.5%	6.0%	6.5%	5.5%	6.0%	6.5%
3.0%	15.3%	14.0%	12.9%	15.6%	14.3%	13.2%
3.5%	15.1%	13.8%	12.8%	15.3%	14.0%	12.9%
4.0%	14.8%	13.6%	12.5%	14.8%	13.6%	12.5%

**assumes net external financing requirements of $86 billion from 1975-1980, and $174 billion from 1975-1985*

As shown in the table below, the utility industry's pollution control requirements similarly increase the industry's needs relative to total corporate needs by a discernible amount. The increase is 2 percentage points in both Scenarios 1 and 2. In the low total corporate investment scenario, Scenario 3, electric utility financing with pollution control equipment would jump 4 points to 36 percent.

INVESTOR-OWNED ELECTRIC UTILITY
1975-1985 EXTERNAL FINANCING NEEDS BEFORE POLLUTION CONTROL
(billions of 1975 dollars)

	Credit Cycle 5	Scenario 1	Scenario 2	Scenario 3
Non-Financial Corporations	249	$1041	$789	$484
Electric Utility Financing	44	155	155	155
Percent of all Corporate Financing	18%	15%	20%	32%
Percent of all Household Savings	11.5%	12.5%	12.5%	12.8%

PROJECTED FINANCIAL STRENGTH OF INVESTOR-OWNED UTILITIES

Because of the large scale of the electric utility industry's future financing needs, the industry's future financial strength is a vital factor in determining whether the industry is able to compete successfully for these funds against other corporations and other sectors. As discussed in Chapter 4, interest coverage ratios are one important measure of financial strength. Returns on common equity are another. The former controls a company's access to debt financing, the latter controls its access to common stock financing.

Strength Before Pollution Control Needs

Under the assumptions outlined in Volume II, notably a 14 percent return on common equity and a 10 percent interest rate on new issues of debt, the industry's projected external financing would result in interest coverage ratios for the investor-owned industry as a whole that decline slightly from the range of 2.5 to 2.9 in 1976 to the range of 2.4 to 2.7 in 1985[1] (see Exhibit IV-32). Those ratios would be sufficient, at least under historical capital market conditions, to enable the industry to meet its external long-term debt needs.

As is discussed in more detail in Chapter 6 and as is shown in the following table, interest coverage ratios are strongly influenced by returns on equity. If the industry's future return on equity remains at its current level of about 11 percent, then (unless interest rates on new debt issues drop well below the 10 percent level assumed in this analysis) the industry's average interest coverages would drop to 2.1 to 2.4 in 1980 and to 2.0 to 2.4 in 1985. As is also documented in Chapter 6, average interest coverage figures typically are an aggregate over a wide range of individual utility ratios, so that an average coverage level of 2.0 to 2.4 implies that some significant number of individual systems will be under the 2.0 level typically required in mortgage bond indentures. Thus, if the industry's future return on equity is held low relative to interest rates, some firms will find themselves excluded from the debt market.

---

[1] *Because some bond indentures restrict the amount of AFDC which can be included in earnigs before interest and taxes for the purpose of interest coverage computation, the range shown in this report represents the coverage ratios computed with no AFDC in earnings, the worst possible assumption concerning the stringency of the indenture requirement, and with all AFDC in earnings, the easiest possible constraint for the industry to meet.*

COMPARISON OF BASELINE RESULTS UNDER
11% AND 14% RETURN ON EQUITY (ROE)
(billions of 1975 dollars)

	14% ROE	11% ROE	% Change
External Financing (1975-1985)	155.0	161.0	+4%
Revenues in 1985	96.76	91.09	-6%
Interest Coverage in 1985			
Including AFDC	2.7	2.4	
Excluding AFDC	2.4	2.0	

As described above, the return on equity allowed by regulators is important because of its impact on coverage ratios. As discussed in Chapter 4, it is also of major importance because of its impact on the industry's common stock price and its ease of access to equity financing. The issuance of common stock at prices below book value is possible for brief periods of time, but as is argued in detail in Appendix A, is infeasible over long periods. Thus, the key to the industry's ability to raise common equity is a level of allowed return on equity commensurate with the returns available in the market on investments of comparable risk.

The level of return on equity assumed in the analysis does not greatly affect external financing requirements, total financing costs, or revenues. As shown in the table above, if returns on equity are 11 percent rather than 14 percent, so that the industry's retained earnings are lower, external financing requirements increase slightly, by about 4 percent. The lower return on equity may, of course, result in very much greater difficulties in raising equity capital. Assuming that the industry could somehow raise adequate equity and debt with an 11 percent return on equity, financing costs--and therefore consumer charges--would be reduced by only 6 percent.

The Effect of Pollution Control Needs

The impact of pollution control financing on the industry's coverage ratios depends on the strategy employed by the industry to finance these needs. Three alternative financing strategies are analyzed below. These assume:

- First, that the historical mix of debt, preferred stock, and equity financing is used;
- Second, that the industry is in enough difficulty with interest coverage requirements that all additional investments for pollution control must be financed totally with new common equity issues; and
- Third, that all pollution control financing is done through pollution control revenue bonds (PCRB's).

Of course, the best future strategy may combine elements of each of these financing strategies. However, the analysis of the three polar cases indicates the degree to which the industry's coverages and revenue impacts are sensitive to financing strategy. The results of each of these projected strategies are shown in the table on the following page.

IMPACT OF POLLUTION CONTROL FINANCING
INVESTOR-OWNED SYSTEMS
(billions of 1975 dollars)

	1975-1985 Incremental Financing		
New Financing	Historical Financing Mix	All Equity	All PCRB's
Long-Term Debt	10.6	0	0
Preferred Stock	1.9	0	0
Common Stock	6.8	19.3	0
PCRB's			19.3
TOTAL	19.3	19.3	19.3
Coverage Ratio with AFDC in 1985	2.7	3.1	2.5
Coverage Ratio without AFDC in 1985	2.4	2.7	2.2

As shown in this table, financing the industry's total pollution control needs of $19.3 billion over the 1975-1985 period would result in increments of $10.6 billion in the industry's long-term debt issues, $1.9 billion in preferred stock, and $6.8 billion in common stock. As is also shown in the table, this strategy will tend to maintain the industry's coverage ratios at pre-pollution control levels (see Exhibit IV-33). While this additional financing would not significantly alter interest coverage ratios from the baseline case, it would cause increases in consumer charges of 2.3 percent in 1980 and 2.0 percent in 1985 to cover increased financing costs.[2]

If the industry's coverage ratios or other considerations preclude the use of debt or preferred stock for pollution control financing, the industry's only recourse would be to attempt to use common stock financing. Exhibit IV-34 and the summary table above show the coverage impacts of financing the entire $19.3 billion of pollution control needs by means of common stock. Interest coverage would increase because interest charges remain unchanged and because earnings must increase to provide a return on the additional equity invested. Assuming that regulators allow a 14 percent return, interest coverages would increase to the range of 2.7 to 3.1 by 1985. The disadvantage of this strategy is that it would cause a substantial increase in average consumer charges. Consumer charges would be 3.7 percent higher in 1980 and 3.3 percent higher in 1985 than before consideration of pollution control financing costs.

---

[2] *These increases in consumer charges are those directly attributable to the incremental financing brought about by federal pollution control requirements. As discussed in Volume III, the total increase in consumer charges including incremental operating and maintenance expenses is 5.3 and 6.7 percent in 1980 and 1985, respectively.*

Pollution control revenue bonds, which in effect allow utilities to issue debt obligations in the name of state agencies (and thus at interest rates reflecting the favorable tax treatment accorded the recipients of interest on these securities), are a special source of financing for pollution control equipment, but are not a panacea. PCRB's are not guaranteed by the issuing agency and hence typically carry bond quality ratings equal to unsecured debt of the utility using the pollution control equipment. This rating is generally one notch below the utility's mortgage bonds. As a result, companies whose mortgage debt is rated Baa or a weak A sometimes are hard put to issue PCRB's. This problem -- and the level of interest rates on issues that do come to market -- may be heightened at least in the short run if large volumes of PCRB's begin to flood the calendar for municipal securities.

If available, financing with PCRB's is the least expensive to consumers because the interest rates on such securities are approximately two-thirds those of other long-term debt. Nonetheless, they do erode coverage ratios slightly. Again assuming a 14 percent return on equity, the coverage ratios under this scenario would decline to the range of 2.2 to 2.5 in 1985. The impact, listed in Exhibit IV-35 and summarized in the table above, seems slight. In view of the precarious current positions of many utilities, however, this drop in coverage could be enough to preclude the use of PCRB's. In fact, if the industry's future rate of return on equity is 11 percent instead of 14 percent, then 1985 coverage ratios would drop to the range of 1.9 to 2.2 As suggested above, the impact on consumer charges would be lower with this type of financing than with any other. Relative to the baseline, this financing strategy would increase consumer charges by only 1.2 percent in 1980 and 1.0 percent in 1985.

Because the feasibility of even the PCRB financing strategy depends on the industry's allowed return on equity, the conclusions reached in the baseline financing discussion concerning the importance of the industry's returns carry over to this discussion of pollution control financing. In fact, because the industry's total financing needs are amplified by pollution control requirements, the importance of a strong financing profile is perhaps also amplified.

CONCLUDING COMMENTS

While the effect of the industry's pollution control requirements is to aggravate an already large financing burden, the increase is not a quantum change and the remarks applicable to the baseline projection apply almost without change to the projections including pollution control. Although a host of caveats concerning GNP growth rates, net household savings rates, the financing needs of other corporations and other sectors, etc. are applicable, the conclusion that emerges from the foregoing analysis can be put simply: Unless the industry's allowed return on common equity is commensurate with the rates of return required in the capital markets, the industry will, in part, be "crowded out" in the competition for funds by stronger industries and sectors. If so, pollution control expenditures can be financed only if expenditures for basic capacity additions are curtailed. On the other hand, if returns are set adequately high by regulatory commissions, the industry's status as a regulated monopoly offering safe and predictable returns should enable it to compete effectively for the funds needed for both basic capacity additions and pollution control equipment. In short, the feasibility of the external financing projections of this chapter depends essentially on the decisions of state regulatory commissions.

CHAPTER 6

FINANCING PROBLEMS OF INDIVIDUAL SYSTEMS

This chapter discusses the factors which govern the ability of an individual, investor-owned electric utility to gain access to the capital markets. The discussion is of importance because, even if the capital market has adequate funds to meet the future needs of electric utilities as a group and even if the industry's average return on equity and interest coverages seem adequate to attract investors, the special problems of individual systems can cause them serious financing difficulties.

The chapter begins with a characterization of individual systems in terms of three categories of financial health. Recent historical data concerning return on equity and interest coverage ratios for a sample of companies are presented in the following section, together with a discussion of the implications of these data for a company's ability to raise funds. Then follows a detailed discussion of the determinants of interest coverage. The chapter concludes with some observations concerning ways to resolve the financing problems of individual electric utilities.

THREE CATEGORIES OF FINANCIAL HEALTH

As an aid to understanding the implications of the financial variables discussed in the preceding section, it is convenient to partition the companies in the electric utility industry into three categories of financial health These categories describe the ease of access to financing for companies in each group according to the levels of return on equity[1] and interest coverage representative of the group.

Although specific levels of return and interest coverage which are representative today are referenced in this discussion, the particular level of return which determines the ability of a company to finance itself will actually vary over time in response to changes in several factors. As an example, an electric utility's return on equity must be considered in relation to the general level of capital market rates prevailing at any time. In addition, required electric utility returns are also influenced by investor's risk perceptions.

TBS' projections were based on an assumed return on equity of 14 percent and a 10 percent interest rate on long-term debt. As discussed in Volume II, these values were chosen to be roughly consistent with required rates of return on the industry's securities in 1975. In early 1976, required rates of return seem to have declined somewhat, and if this trend persists, the required rates of return for electric utilities could indeed decline from those described below.

The first category of financial health comprises those companies with returns on equity and coverage ratios acceptable to the traditional buyers of utility securities. Most of the companies satisfying these criteria should have ready access to both debt and equity financing and should be able to finance both their baseline capital expenditures and expenditures for pollution control equipment without difficulty. In early 1976, a return on equity of 13 to 14 percent and an interest coverage of about 2.8 were financial statistics that tended to result in stock prices at or above book value and in bond ratings of A or better and hence gave companies with these statistics relatively easy access to capital.

---

[1] *The return on equity criterion could alternatively be stated in terms of the market price to book value ratio. The implications of this measure are discussed in detail in Appendix A.*

A second, broad group of companies comprises those with returns on equity and interest coverages near the minimum acceptable to equity and debt investors. Recently the levels in this category would probably include returns on equity in the range of 11.1 to 13.0 percent and interest coverages from 2.2 to 2.8. Most companies in this category have had access to debt financing at reasonable costs. Given the rates of inflation and levels of uncertainty about the electric utility industry characteristic of the 1974-1975 period, most companies in this category might have found it necessary to issue common stock at a discount from book value, but as of early 1976, some companies in this range of returns had stock prices above book value. And, if general rates of price inflation and the returns demanded by the utility investors drop in the 1976-1985 period--drop below those of 1974-1975, as seems to be the current consensus of financial economists--such companies should be able to issue common stock at prices roughly equal to book value. While companies in this second category typically have some access to the capital markets, their financial fragility should be noted. Moreover, their access to debt at reasonable cost is, at least at present, not unlimited. Thus, without changes in the regulatory policies of 1975, these companies may be in the position of having to choose between expenditures for future capacity expansion and expenditures for pollution control equipment.

A third category of companies, those having low returns on equity and coverage ratios, are companies that might have difficulty--perhaps severe difficulty--in financing the capital expenditures required merely to meet the growth in demand in their service areas. At the end of 1975, companies with returns on equity less than 11 percent and coverage below 2.1 were in this category. For these companies, capital expenditures for pollution control equipment tend to cause dollar for dollar reductions in capital expenditures for basic capacity.

It should be noted that, in some instances, companies may have relatively strong return on equity figures, but weak coverage ratios and vice versa. The linkages between return on equity and coverage ratios are analyzed in a later section.

INTERCOMPANY COMPARISONS OF RETURNS AND INTEREST COVERAGE

An examination of the financial data for selected companies for 1975 reveals major differences in return on equity and coverage within the industry. These data underscore the importance of performing financial analysis at the company level. For example, while the average coverage ratio for the companies in this sample is about 2.7, there are a number of companies with coverages well below 2.0. These electric utilities almost certainly confronted severe financing difficulties in 1975.

As shown in the table below, the average return on equity in 1975 was 11.5 percent for normalizing companies and 10.8 percent for flow-through companies. Both average figures are somewhat below the rates of return demanded by investors in such securities in 1975; more important, the averages obscure the severely depressed level of earnings of a significant number of companies in this sample.

RETURN ON EQUITY IN 1975
AVERAGE AND DISTRIBUTION FROM SAMPLE DATA

Average Return: 11.5 % Normalized
10.8 Flow Through

Distribution of Return in Sample (as % of 88 sample companies)

	<10%	10-11.0%	11.1-12.0%	12.1-13.0%	>13%	Total
Normalized	12%	6%	18%	8%	17%	61%
Flow Through	8	10	4	9	8	39
TOTAL	20%	16%	22%	17%	25%	100%

Source: Investors Management Sciences, as reported in Electrical Week

Of the 88 companies in the sample, 36 percent had returns on equity less than 11.0 percent and 20 percent had returns less than 10 percent. An analysis of the market price to book value ratios for some of the lower return companies suggests that these companies doubtless were severely constrained in their common stock financing during 1975. Further, the data below suggest that large companies are by no means exempt from these financial difficulties. The largest companies in the sample have consistently lower returns on common equity than the total sample.

RETURN ON EQUITY IN 1975
LARGE SYSTEMS VS. ALL SAMPLE SYSTEMS

Distribution of Return in Sample (as % of total companies in sample)

	< 10.0%	10.0%-11.0%	11.1%-12.0%	12.1%-13.0%	> 13.0%
Largest 30 Companies[1]	28%	21%	21%	10%	20%
Cumulative	28	49	70	80	100
Total Sample	20	16	22	17	25
Cumulative	20	36	58	75	100

---

[1] *15 Flow-Through and 15 Normalized with highest revenues*

Source: Investors Management Sciences, as reported in Electrical Week

Similarly, the table below suggests that there exist major differences in interest coverage ratios across companies in the industry. Despite an average coverage for 1975 of 2.7 times when AFDC is included in earnings, 8 of the 119 companies in this sample had interest coverage ratios of less than 2.0, and when AFDC is excluded from earnings, the low-coverage group comprises 25 companies, or 21 percent of the sample.

ELECTRIC UTILITY INTEREST COVERAGES
1975

		Interest Coverage		
	Number of Companies	Average	Range of Expected Values*	Number of Companies Below 2.0
Aa or Higher	44			
With AFDC		3.4	4.2 - 2.7	0
Without AFDC		3.0	4.0 - 2.4	1
A	53			
With AFDC		2.6	3.2 - 2.3	2
Without AFDC		2.3	2.9 - 1.9	13
Baa	22			
With AFDC		2.2	2.6 - 1.8	6
Without AFDC		1.9	2.4 - 1.4	11

**90 percent of companies fall within range*

Source: R.W. Pressprich & Co., Inc., March 1976

Although the average interest coverage for the top-rated (Aa or better) companies is 3.0 to 3.4, excluding and including AFDC, the range comprising 90 percent of the group is from 4.0 to 2.4 excluding AFDC and 4.2 to 2.7 including AFDC. For A-rated companies, the average declines to 2.3 to 2.6, and there are a number of companies with coverages below 2.0.

Finally, among the Baa group, the average coverage including AFDC is only 2.2, with approximately 90 percent of the coverages falling between 1.8 and 2.6. When AFDC is excluded, the average drops to 1.9, and 11 of the 22 companies have coverages below 2.0.

The data above clearly indicate that, even though the industry average interest coverage ratio of 2.7 in 1975 suggests a comfortable financial position, there was a wide spread of coverages and return on equity in the industry and a significant number of companies were in a precarious financial position. Another factor which represents a possible flaw in the apparent strength of some companies' coverages is that some coverages include earnings attributable to revenues subject to refund. And, for some systems in recent years, these revenues have represented a significant portion of total earnings. For such companies, refunds dictated by their regulatory commissions could severely damage their returns on equity and coverage ratios.

The distribution of electric utility companies' returns on equity and interest coverages as of the end of 1975 suggests that approximately 25 to 35 percent of the companies had returns and coverages high enough to give them reasonably good access to external financing. Roughly 40 percent of the industry could be categorized as companies with reasonably good access to debt capital, though not in unlimited quantities, and with some access to equity capital, but perhaps at prices below book value. Roughly 25 to 35 percent of all electric utility companies were in 1975 in the precarious third category of firms having low returns, low coverages, and poor prospects for meeting their full financing needs. Unless regulators raise the allowed return for this latter group of companies, or otherwise improve their financial profile, most of them will experience great difficulty in attempting to finance both baseline expansion and pollution control between 1976 and 1985.

DETERMINANTS OF INTEREST COVERAGE RATIOS

A return on common equity is set directly by the actions of regulatory agencies; coverage ratios are determined in part by factors outside the control of commissions. Return on equity is one determinant of coverage ratios, but coverages are affected also by a company's average interest rate, its average income tax rate as shown in its regulatory financial statements, and the amount of its allowance for funds used during construction (AFDC). The interactions between the factors influencing interest coverage ratios can perhaps best be displayed by means of a series of simple numerical illustrations.

Exhibit IV-36 sets out some capital structure, capital cost, and income tax rate assumptions for several hypothetical electric utilities. In each case, an income statement is developed that, working from the bottom up, provides the appropriate amount of income available for common, dividends for preferred stock, tax payments, and interest. As shown in Case I, with the interest rates, returns on book value of equity, and income tax rates characteristic of the 1960s, interest coverages are high enough to meet a 2.00 coverage criterion with ease.

Increases in interest rates, even where returns on equity are not adversely affected, can have a severe adverse impact in coverage ratios. As shown in Case II, as debt costs increase by 4 percentage points relative to Case I, interest coverage ratios drop from 2.56 to 1.93. Conversely, lower interest rates would help alleviate the plight of utilities currently having coverage problems.

Lower interest rates on debt could come about because of reductions in the current rate of inflation. At least for the portion of financing represented by pollution control equipment, lower interest rates could conceivably also come about from the use of pollution control revenue bonds. As discussed in preceding chapters, PCRBs pay interest that is exempt from federal income taxation of the recipient and, as a result, tend to require lower pretax interest rates than other securities of comparable risk. Unfortunately, however, PCRBs typically rank below mortgage bonds in safety. Thus, their tax advantage is somewhat offset by their risk disadvantage. At present, the net result of these advantages and disadvantages is that PCRBs sell at yields only slightly, if at all, lower than mortgage bonds. And, the PCRBs of companies with low-rated bonds have recently proven hard to sell even at elevated yields. Thus, while PCRBs may be helpful to those companies able to issue them at all, they offer no panacea for companies at the low end of the interest coverage spectrum.

The effective rate of income tax paid by a company also impacts coverage ratios. As can be seen by comparing Case III and Case II in Exhibit IV-36, a reduction in the effective tax rate from 25 percent to 0 percent lowers the required amount of earnings before interest and taxes and thus severely depresses coverage ratios. This point is of particular importance because the effect of flow-through accounting for statutory purposes is to reduce effective tax rates relative to those in normalizing companies. Thus, regulatory accounting practices as specified by the various state commissions can have a major impact on coverage ratios. Flow-through accounting does, of course, result in revenue requirements that are lower, at least in the short run. As can be seen by comparing the required earnings before interest and taxes in Case II and III, the 25 percent tax rate assumption requires earnings before interest and tax higher by $14. Although this $14 amount represents a reduction of more than 10 percent in earnings before interest and taxes, revenues and consumer charges would of course decline by much smaller percentage amounts.

Case IV illustrates the fact that higher returns on equity lead to higher coverage ratios. As can be seen by comparing Case IV and Case I, however, equal percentage point increases in the costs of debt, preferred stock and common stock do not result in returns on equity high enough to preserve the coverage ratio of Case I. Thus, to the extent that increases in the general rate of inflation increase nominal (current dollar) returns on debt and equity by equal amounts, the higher the rate of inflation, the worse are coverages.

As is shown in Case V, one way of increasing coverage ratios is to reduce the portion of debt in a company's capital structure. Unfortunately, unless interest and common stock costs drop as a result of this capital structure change, the earnings before interest and tax, and hence operating revenues, required to cover these capital costs rises. Comparing Case V and Case IV, the low-debt alternative results in an increase in coverage ratios from 1.97 to 2.20, but increases the earnings before interest and tax required by $3.

Because "other income" such as AFDC is not fully includible in "earnings" as defined for interest coverage purposes in the financing agreements of many utilities, a final problem is that the higher AFDC is in relation to required earnings before interest and tax, the less useful some portion of earnings before interest and tax is for interest coverage purposes. The amount of required earnings before interest and tax is unaffected by AFDC, but coverages are affected. As a result, the higher the rate of a company's new construction, the greater are both its external financing needs and its interest coverage problems. Exhibit IV-37 shows that, for a company with high AFDC, interest coverage as computed for indenture purposes could be radically affected by a limitation on the amount of AFDC allowed for interest coverage purposes.

CONCLUSIONS CONCERNING ELECTRIC UTILITY FINANCING PROBLEMS

The foregoing analysis suggests that, even if the capital markets are large enough to accommodate the electric utility industry's total needs under current regulatory policy, some of the companies within the industry will have difficulty in raising sufficient capital to meet their baseline capital needs, much less the needs associated with pollution control equipment. Nonetheless, it is within the power of the current regulatory system to effect changes that should enable all companies to meet both baseline and pollution control financing needs. Put bluntly, regulators need to allow price increases or force cost reductions resulting in higher returns on equity and higher interest coverage ratios. Moreover, if the industry's financing requirements grow to constitute a large fraction of total corporate financing, the ratios must be high enough to make utility debt and equity securities of extremely high quality.

Recent financial data suggest that between 25 and 35 percent of the companies in the industry had returns on equity and interest coverages low enough at the end of 1975 to put them in a somewhat precarious financial position. Unless industry regulators, managers, or some outside force improves the position of this group vis-a-vis investor demands, this significant segment of the industry will find it extremely difficult to compete successfully in the markets. For this group, until financial conditions improve, the companies may not be able to finance all of their projected expenditures for capacity additions. Thus, pollution control can be financed perhaps only at the partial expense of expenditures for basic capacity requirements.

As suggested above, regulatory agencies have several routes for improving the financial statistics of utilities under their jurisdiction. Most, however, tend to result in electricity prices that are higher at least in the short run. These alternatives include increasing returns on common equity, increasing statutory taxes via conversions (where possible) from flow-through to normalizing accounting, and reducing AFDC via allowing companies to include construction work in progress in the rate base.

Exhibit IV-1

TOTAL USES OF FUNDS AND FINANCING NEED BY YEAR

Domestic Non-Financial Business Corporations
1960-1974
(billions of dollars)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Real Assets	$38.7	$36.3	$43.6	$45.2	$51.6	$62.3	$76.5	$71.4	$75.0	$83.0	$84.0	$87.2	$102.5	$121.5	$125.9
Plant and Equipment	34.6	32.9	36.6	38.2	43.7	52.3	61.1	61.9	66.5	74.0	75.1	77.1	87.1	103.3	111.7
Residential Construction	1.1	1.9	2.3	2.6	2.1	2.0	1.1	2.3	2.1	2.9	3.3	4.9	5.7	5.3	3.2
Inventory	3.0	1.5	4.7	4.3	5.9	7.9	14.4	7.3	6.4	6.7	5.7	5.1	9.7	12.9	10.9
Net Financial Assets	(0.6)	7.9	7.1	6.8	8.2	8.0	1.9	9.2	11.5	6.6	4.4	19.2	16.7	18.8	23.6
Liquid Assets	(4.1)	3.2	3.7	4.8	1.2	2.6	(3.7)	4.8	8.0	2.3	(0.4)	10.6	4.0	6.9	13.2
Net Trade and Consumer Credit	1.4	2.6	1.5	(0.1)	2.6	2.1	2.0	1.2	1.4	2.1	1.6	2.5	7.9	6.5	4.0
New Miscellaneous Assets	2.1	2.1	1.9	2.1	2.8	3.3	3.6	3.2	2.1	2.2	3.2	6.1	4.8	5.4	6.4
Discrepancy	6.0	5.0	4.5	5.6	7.4	8.9	8.3	5.9	9.6	6.0	6.7	10.2	14.8	13.8	13.6
Total Financing Need	$44.1	$49.2	$55.2	$57.6	$67.2	$79.2	$86.7	$86.5	$96.1	$96.3	$95.3	$116.8	$133.9	$154.1	$163.1

Source: Flow of Funds Statistics, Board of Governors of the Federal Reserve System, Third Quarter 1975

Preceding page blank

Exhibit IV-2

USES OF FUNDS AND FINANCING NEEDS IN FIVE CREDIT CYCLES

Domestic Non-Financial Business Corporations

(all data are flows as a percent of GNP averaged over recent credit cycles)

(third quarter 1954 to fourth quarter 1974)

	Credit Cycle 1 1954:3 to 1958:1	Credit Cycle 2 1958:2 to 1960:4	Credit Cycle 3 1961:1 to 1967:1	Credit Cycle 4 1967:2 to 1970:3	Credit Cycle 5 1970:4 to 1974:4
Total Real Assets	7.6	7.2	8.3	8.8	8.9
Plant and Equipment	6.9	6.5	7.0	7.8	7.7
Residential Construction	0.2	0.3	0.3	0.3	0.4
Inventory	0.5	0.4	1.0	0.7	0.8
Net Financial Assets	0.9	1.1	1.1	1.0	1.5
Discrepancy	0.9	1.0	1.1	0.7	1.1
Total Financing Need	9.5	9.3	10.5	10.6	11.4

Source: Flows of Funds Statistics, Board of Governors of the Federal Reserve System, Third Quarter 1975

Exhibit IV-3

SOURCES OF FUNDS BY YEAR

Domestic Non-Financial Business Corporations
1960-1974
(billions of dollars)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Total Financing Need	$44.1	$49.2	$55.2	$57.6	$67.2	$79.2	$86.7	$86.5	$96.1	$96.3	$95.3	$116.8	$133.9	$154.1	$163.1
Funds Internally Generated	34.4	35.6	41.8	43.9	50.5	56.6	61.2	61.5	61.7	60.7	59.4	68.0	78.7	84.6	81.5
Adjusted Retained Profits	10.1	10.1	12.7	13.1	17.7	21.2	23.0	20.0	16.6	10.9	5.8	10.3	15.7	17.1	9.0
Capital Consumption Allowances (Depreciation)	24.2	25.4	29.2	30.8	32.8	35.2	38.2	41.5	45.1	49.8	53.6	57.7	63.0	67.5	72.5
External Funds Raised	9.7	13.7	13.4	13.7	15.0	22.6	25.6	24.9	34.4	35.6	35.8	48.8	55.2	69.5	81.5
Bank Loans and Other Short-Term Debt	2.1	2.8	3.9	5.5	6.1	13.4	10.1	3.5	16.1	15.5	5.2	7.0	15.9	34.9	45.3
Long-Term Funds	7.5	10.8	9.5	8.2	8.9	9.2	15.5	21.4	18.4	20.0	30.4	41.5	39.2	34.5	36.3
Equity	1.5	2.2	0.4	(0.6)	1.3	(0.1)	1.1	2.2	(0.2)	3.4	5.7	11.4	10.9	7.4	4.1
Long-Term Debt[1]	6.0	8.6	9.1	8.8	7.6	9.3	14.4	19.2	18.6	16.6	24.7	30.1	28.3	27.1	32.2
Mortgage Bonds	2.5	4.0	4.5	4.9	3.6	3.9	4.2	4.5	5.7	4.6	5.2	11.3	15.6	16.1	10.9
Debentures[1]	3.5	4.6	4.6	3.9	4.0	5.4	10.2	14.7	12.9	12.0	19.5	18.8	12.2	9.2	21.3

[1] *Includes tax exempt financing, 1971 to 1973*

Source: Flow of Funds Statistics, Board of Governors of the Federal Reserve System, Third Quarter 1975

Notes to Exhibit IV-3

Explanation of terms:

Total Financing Need: The cash used to finance business activity, including both the cash used to fund investment in physical assets such as plant and equipment and the value of the increase in physical inventories, and the cash necessary to fund financial requirements such as net trade credit and short-term financial assets.

Funds Internally Generated: The funds provided by ongoing operations, including both the cash generated by earnings and by depreciation.

External Funds Raised: The funds which must be raised externally in the capital markets, either through intermediaries such as commercial banks or directly through the issuance of securities.

Adjusted Retained Profits: The cash realized from reported earnings which is available for investment in the firm (computed by taking profits before taxes, adding repatriated foreign profits, and subtracting corporate profit taxes, dividends, and the inventory valuation adjustment which measures the component of profits due solely to increased inventory values.)

Capital Consumption Allowances: The non-cash expense items including principally depreciation and depletion allowances which have been subtracted at an earlier stage to yield profits before tax, but which do not represent a cash outflow, are merely an accounting recognition of past cash expenditures.

Equity: The net funds raised from equity sources in the period, including the cash received from gross new issues of equity minus equity retirements for various purposes.

Long-Term Debt: The net increase in outstanding external long-term debt in the period, including debentures, bonds, and in recent years some small amounts of tax-exempt pollution control bonds.

Long-Term Funds: The sum of equity and long-term debt.

Exhibit IV-4

SOURCES OF FUNDS IN FIVE CREDIT CYCLES

Domestic Non-Financial Business Corporations
(all data are flows as a percent of GNP averaged over recent credit cycles)
(third quarter 1954 to fourth quarter 1974)

	Credit Cycle 1 1954:3 to 1958:1	Credit Cycle 2 1958:2 to 1960:4	Credit Cycle 3 1961:1 to 1967:1	Credit Cycle 4 1967:2 to 1970:3	Credit Cycle 5 1970:4 to 1974:4
Total Sources of Funds	9.5	9.3	10.5	10.6	11.4
Funds Internally Generated	6.9	6.9	7.7	6.9	6.4
Adjusted Retained Earnings	2.5	2.2	2.6	1.6	1.0
Capital Consumption	4.4	4.8	5.1	5.3	5.3
External Funds Raised	2.5	2.4	2.7	3.7	5.1
Bank Loans and Other Short-Term Debt	0.6	0.6	1.0	1.2	1.9
Long-Term Funds	1.9	1.8	1.7	2.5	3.2
Equity	0.4	0.4	0.1	0.3	0.7
Long-Term Debt	1.5	1.4	1.6	2.2	2.5
Increase in Liquid Assets	0.1	0.3	0.3	0.5	0.7
Net External Funds Required	2.4	2.1	2.5	3.2	4.3

Source: Flow of Funds Statistics, Board of Governors of the Federal Reserve System, Third Quarter 1975

Exhibit IV-5

THE CYCLES OF EXTERNAL FUNDS--SHORT-TERM DEBT, LONG-TERM DEBT, NET EQUITY ISSUES
Non-Financial Business Corporations
Third Quarter 1954 to Second Quarter 1974
(seasonally adjusted, smoothed, annual rates as a percent of GNP)

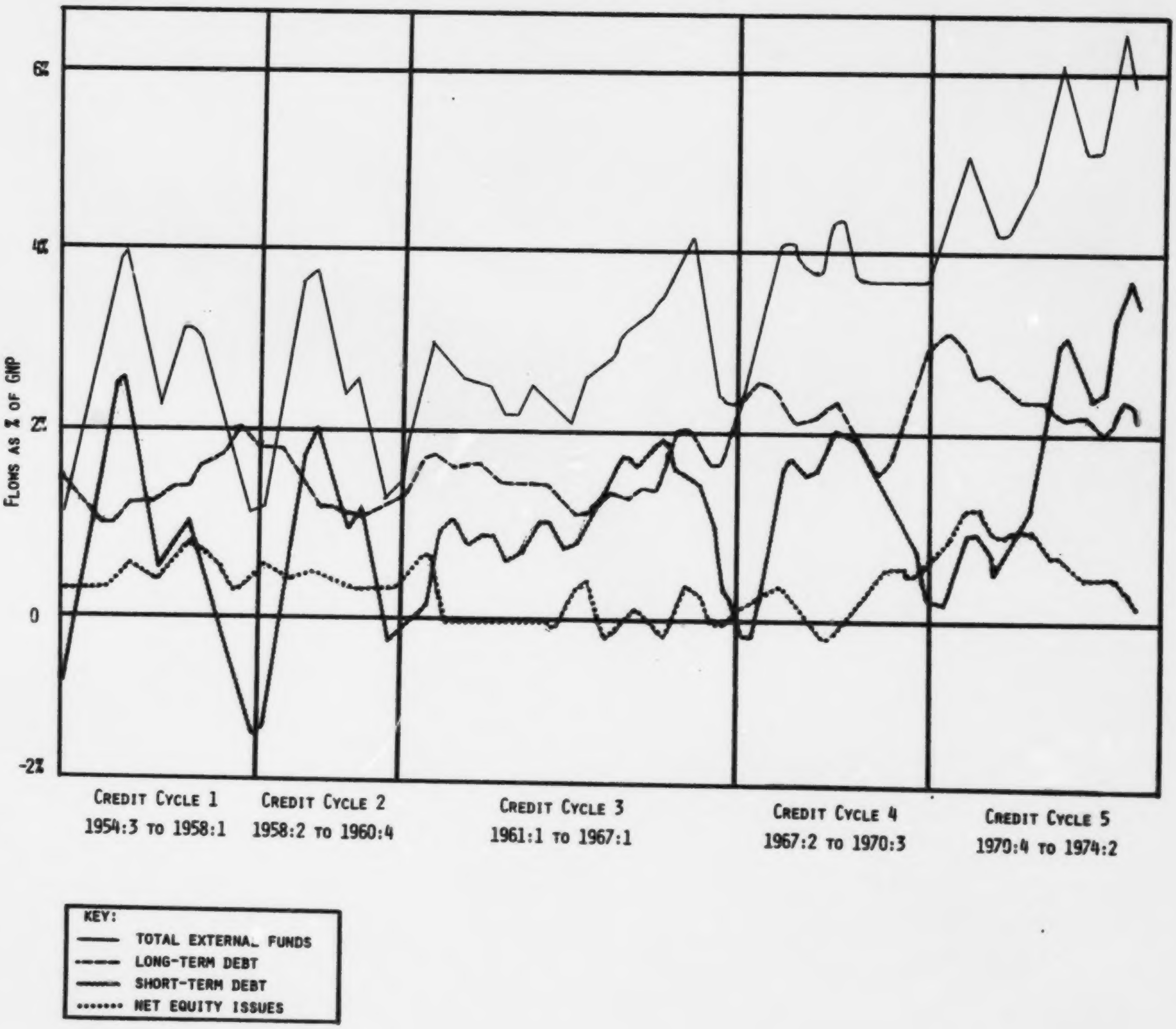


Exhibit IV-6
LEVELS OF LIQUID ASSETS AND DEBT OUTSTANDING, AS PERCENT OF GNP
Non-Financial Business Corporations

Third Quarter 1954 to Fourth Quarter 1974

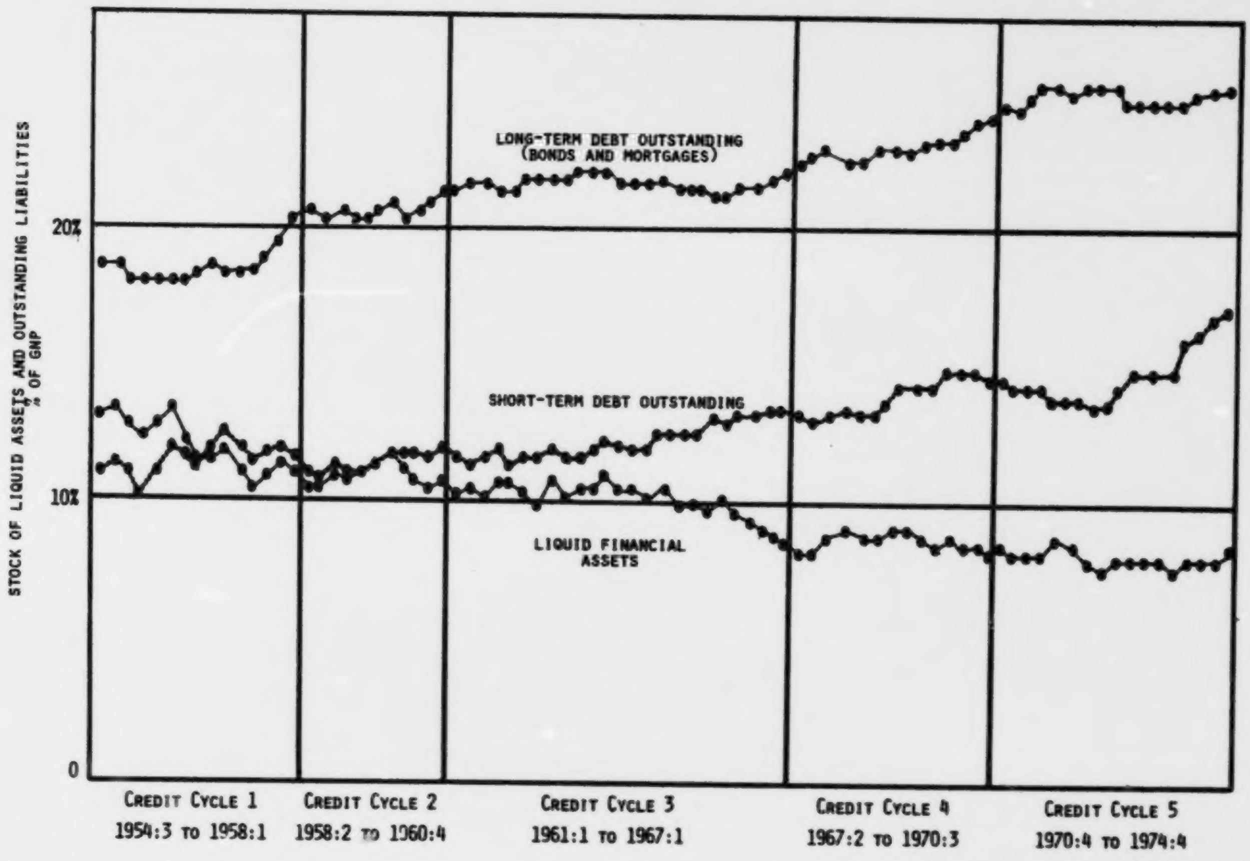


Exhibit IV-7

NET INCREASE IN FINANCIAL LIABILITIES BY YEAR

Major Economic Sectors

1960-1974

(billions of dollars)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Household Borrowing															
Residential Home Mortgages	$10.8	$10.9	$12.7	$14.8	$16.0	$15.2	$12.7	$10.4	$14.6	$16.1	$12.5	$24.2	$38.4	$44.2	$32.6
Consumer Credit	4.6	0.8	5.8	7.9	8.5	9.6	6.3	4.5	10.0	10.4	6.0	11.2	19.1	22.9	9.6
Government Borrowing															
U.S. Treasury Securities[1]	(2.2)	6.7	6.2	4.1	5.4	1.3	2.3	8.9	10.3	(1.3)	12.9	26.0	13.9	7.7	12.0
State/Local Government Securities	5.3	5.1	5.4	5.7	6.0	7.3	5.6	7.8	9.5	9.9	11.3	17.5	13.8	11.9	15.7
Corporate Business (non-financial)															
External Funds Raised	9.7	13.7	13.4	13.7	15.0	22.6	25.6	24.9	34.4	35.6	35.8	48.8	55.2	69.5	81.5

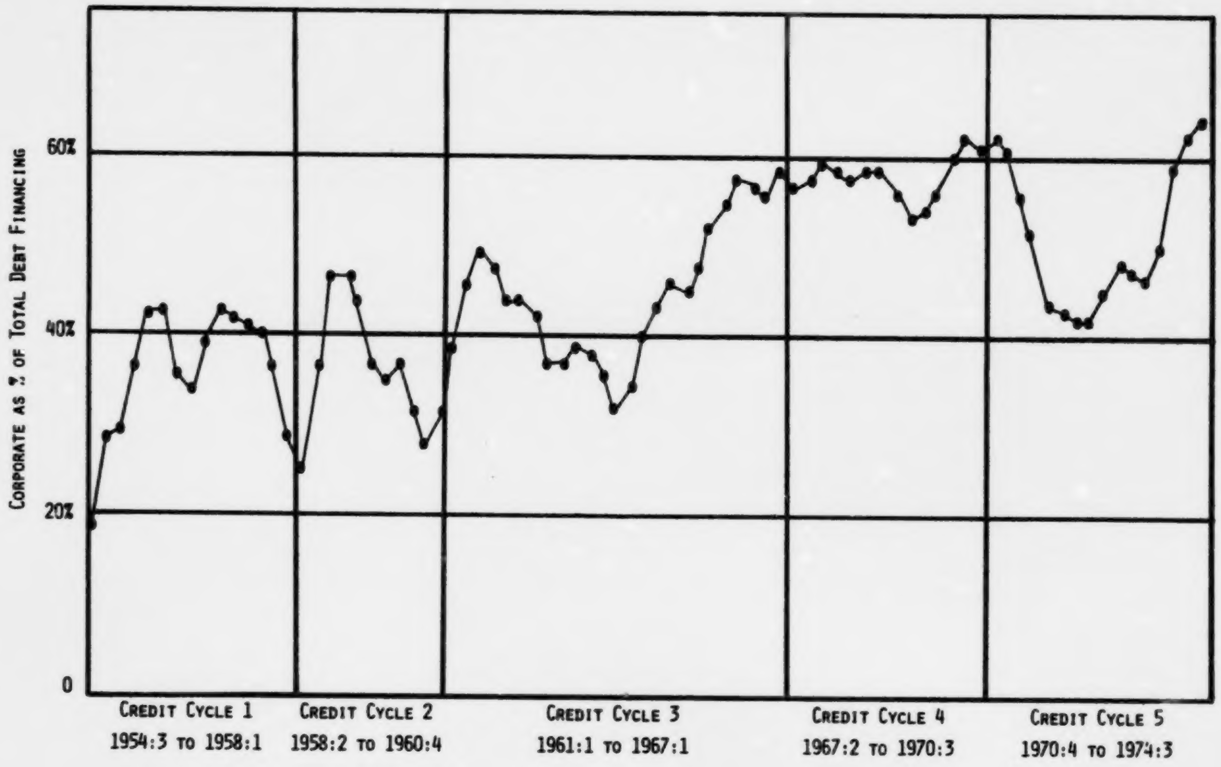
[1] *Net borrowing of the Treasury. A substantial fraction of this debt is purchased by U.S. Trust Funds and the Federal Reserve, and thus these numbers overstate the "net borrowing of the Federal Government sector." On the other hand, many Federal agencies have borrowed heavily in recent years. Because most of this Federal agency borrowing is "recycled" to the mortgage market, it is excluded here.*

Source: Flow of Funds Statistics, Board of Governors of the Federal Reserve System, Third Quarter 1975

EXHIBIT IV-8

CORPORATE BUSINESS DEBT FINANCING AS A PERCENT OF TOTAL PRIVATE SECTOR DEBT FINANCING[1]

THIRD QUARTER 1954 TO THIRD QUARTER 1974



---

[1] SPECIFICALLY, THE INCREASE IN CORPORATE SHORT-TERMS AND LONG-TERM DEBT AS A PERCENT OF THE INCREASE IN CORPORATE SHORT-TERM AND LONG-TERM DEBT PLUS HOME MORTGAGE, FINANCING PLUS CONSUMER CERDIT.

Exhibit IV-9

PROJECTIONS OF FUTURE SOURCES AND USES OF FUNDS

Domestic Non-Financial Business Corporations

(all projections are shown as a percent of GNP averaged over a prospective credit cycle)

	Scenario 1	Scenario 2	Scenario 3
Total Financing Need			
Plant & Equipment	8.8	8.8	7.2
Residential Construction	0.3	0.3	0.3
Inventories	0.8	0.8	0.7
Net Financial Assets	1.2	1.2	1.2
Discrepancy	1.0	1.0	1.0
Total Sources of Funds			
Funds Generated Internally	6.6	7.8	7.5
Adjusted Retained Earnings	1.3	2.5	2.5
Depreciation	5.3	5.3	5.0
External Funds Raised	5.5	4.3	2.9
Increase in Liquid Financial Assets	0.5	0.5	0.5
Net External Funds Required	5.0	3.8	2.4

Source: TBS projections

Exhibit IV-10

SAVINGS BEHAVIOR OF U.S. HOUSEHOLDS

(all data as percent of GNP averaged over a credit cycle)

	Credit Cycle 1 1954:3 to 1958:1	Credit Cycle 2 1958:2 to 1960:4	Credit Cycle 3 1961:1 to 1967:1	Credit Cycle 4 1967:2 to 1970:3	Credit Cycle 5 1970:4 to 1974:4
Net Savings	6.3	5.8	5.4	5.5	6.6
Net Increase In Residential Construction[1]	3.8	3.1	1.9	1.3	1.8
Net Financial Investment[2]	2.5	2.7	3.5	4.2	4.8

[1] Net Increase in Residential Construction is the dollar value of newly constructed 1- to 4-family homes purchased by households, minus the depreciation imputed to the existing stock of such homes owned by households. It does not include changes in the market value of existing homes.

[2] Net Financial Investment is the dollar value of the net purchase of financial assets minus the dollar value of the net increases in financial liabilities for all households.

Source: Federal Reserve Flow of Funds data, second quarter 1975

Exhibit IV-11

PROJECTIONS OF TOTAL CAPITAL NEEDS BY YEAR

Domestic Non-Financial Business Corporations
1975-1985
(billions of 1975 dollars)[1]

Assumptions for:	Scenario 1	Scenario 2	Scenario 3
Real GNP Growth	3.5%	3.5%	3.0%
Level of Plant and Equipment Investment	High	High	Low
Level of Retained Earnings	Low	High	High
Total Corporate Capital Raised, as % of GNP	5.0%	3.8%	2.4%

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	Cumulative 1975-1985
Scenario 1												
GNP (3.5% growth)	1,582	1,638	1,695	1,754	1,816	1,878	1,945	2,013	2,084	2,157	2,233	20,795
Total Corporate Capital Raised (5% GNP)	79	82	85	88	91	94	97	101	104	108	112	1,041
Scenario 2												
GNP (3.5% growth)	1,582	1,638	1,695	1,754	1,816	1,878	1,945	2,013	2,084	2,157	2,233	20,795
Total Corporate Capital Raised (3.8% GNP)	60	62	64	67	69	71	74	76	79	82	85	789
Scenario 3												
GNP (3.0% growth)	1,574	1,622	1,670	1,720	1,772	1,824	1,880	1,936	1,994	2,054	2,116	20,162
Total Corporate Capital Raised (2.4% GNP)	38	39	40	41	43	44	45	46	48	49	51	484

[1] 1975 dollars assumed to include 9.5 percent inflation over 1974 dollars.

Note: Results assume 14 percent return on equity.

Exhibit IV-12

NET INCOME

Privately Owned Class A&B Electric Utilities in the United States
Electric Department
1960-1974

Year	Net Income (in millions)
1960	$1,647
1961	1,731
1962	1,887
1963	1,973
1964	2,189
1965	2,363
1961-1965 Growth Rate	7.4%
1966	2,516
1967	2,661
1968	2,764
1969	2,962
1970	3,141
1971	3,516
1972	4,110
1973	4,680
1966-1973 Growth Rate	8.2%
1974	4,776
1973-1974 Growth Rate	2.0%

Note: Income statement data for this exhibit (and others that pertain to the electric department of combination utilities) have been adjusted to reflect electric department only as follows:

1. Interest has been prorated by ratio of net electric utility plant to net total gas and electric plant, and
2. Allowance for funds during construction (AFDC) has been prorated by ratio of the change in gross electric plant to the change in total gross gas and electric plant.

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973 and preliminary 1974

Exhibit IV-13

EARNINGS AND DIVIDENDS

Privately Owned Class A&B Electric Utilities in the United States
Electric Department

1960-1974

(1) Year	(2) Net Income After Preferred Dividends (millions)	(3) Common Stock Dividends* (millions)	(4) Payout Ratio (3) ÷ (2) (%)	(5) Earnings Per Share	(6) Return on Common Equity (%)
1960	1,473	$1,008	68.4	$4.12	11.6
1961	1,550	1,061	68.4	4.33	11.5
1962	1,702	1,135	66.7	4.73	11.9
1963	1,786	1,233	69.0	4.99	11.8
1964	2,001	1,324	66.2	5.41	12.5
1965	2,171	1,484	68.3	5.92	12.8
1966	2,319	1,544	66.6	6.30	13.0
1967	2,440	1,643	67.3	6.67	13.0
1968	2,511	1,739	69.2	6.67	12.6
1969	2,682	1,824	68.0	6.92	12.7
1970	2,810	1,973	70.2	6.89	11.9
1971	3,062	2,143	70.0	7.14	11.6
1972	3,520	2,304	65.4	7.73	11.9
1973	3,948	2,641	66.9	7.55	11.7
1974	3,885	2,853	73.4	7.63	11.0

*Common stock dividends pro rated by ratio of net electric utility plant to net plant.

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974; Earnings per Share: Survey of Current Business.

Exhibit IV-14

ASSETS PER DOLLAR OF REVENUE

Privately Owned Class A&B Electric Utilities in the United States
Electric Department

1960-1974

(1) Year	(2) Gross Electric Plant Investment (millions)	(3) Operating Revenues (millions)	(4) Gross Plant Per Dollar Of Revenue (2)÷(3)
1960	$ 45,456	$ 10,116	$ 4.49
1961	48,090	10,666	4.51
1962	50,699	11,392	4.45
1963	53,474	12,018	4.45
1964	56,326	12,673	4.44
1965	59,703	13,400	4.46
1961-1965 Growth Rate	5.6%	5.8%	--
1966	64,066	14,374	4.46
1967	69,617	15,225	4.57
1968	76,026	16,359	4.60
1969	83,671	18,023	4.64
1970	93,303	19,791	4.71
1971	104,300	22,322	4.67
1972	116,644	25,355	4.60
1973	130,840	29,104	4.50
1966-1973 Growth Rate	10.3%	10.2%	--
1974	146,007	37,225	3.92
1973-1974 Growth Rate	11.5%	27.5%	--

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974.

Exhibit IV-15

ANNUAL CAPITAL EXPENDITURES VS. TOTAL ASSETS

Privately Owned Electric Utilities in the United States
Electric and Gas Departments

1961-1974

(1) Year	(2) Annual Capital Expenditures (millions)	(3) Total Assets (millions) (beginning of year)	(4) Percentage (2) ÷ (3)
1961	3,256	44,488	7.3
1962	3,154	46,894	6.7
1963	3,319	49,183	6.7
1964	3,551	51,256	6.9
1965	4,027	53,627	7.5
1966	4,932	56,313	8.8
1967	6,120	60,259	10.2
1968	7,140	65,085	11.0
1969	8,294	70,976	11.7
1970	10,145	77,794	13.0
1971	11,894	87,220	13.6
1972	13,385	98,045	13.7
1973	14,907	110,616	13.5
1974	16,350	124,796	13.1

Source: Statistical Yearbook of the Electric Utility Industry,
Edison Electric Institute, 1974

Exhibit IV-16a

SOURCES OF FUNDS

Privately Owned Class A&B Electric Utilities in the United States
Electric and Gas Departments

1960-1974

(millions of dollars)

(1)	External Funds					Internal Funds				(11)
Year	(2) Common Stock	(3) Preferred Stock	(4) Long-Term Debt	(5) Short-Term Debt	(6) Total	(7) Retained Earnings	(8) Deferred Taxes	(9) Depreciation and Amortization	(10) Total	Total Funds
1960	130	201	1,471	9	1,811	468	188	1,197	1,853	3,664
1961	294	153	1,196	(28)	1,615	495	170	1,298	1,963	3,578
1962	243	201	1,356	(120)	1,680	586	161	1,400	2,147	3,827
1963	181	108	1,323	110	1,721	632	143	1,502	2,277	3,998
1964	272	184	1,177	52	1,685	731	125	1,585	2,441	4,126
1965	105	208	1,328	348	1,989	814	115	1,686	2,615	4,604
1966	148	253	2,322	185	2,908	861	111	1,782	2,754	5,662
1967	185	453	2,691	428	3,757	893	135	1,902	2,930	6,687
1968	326	461	3,046	481	4,314	843	163	2,044	3,050	7,364
1969	744	381	3,750	844	5,719	943	163	2,206	3,312	9,031
1970	1,411	1,147	5,674	(104)	8,128	950	136	2,411	3,497	11,625
1971	2,063	1,851	5,455	136	9,505	1,090	293	2,639	4,022	13,527
1972	2,282	2,104	4,330	132	8,848	1,319	697	2,920	4,936	13,784
1973	2,552	1,629	5,082	1,087	10,350	1,427	718	3,270	5,415	15,765
1974	1,951	1,809	8,428	2,578	14,766	1,328	1,002	3,638	5,968	20.734
Compound Growth Rate										
1961-1965	(4.2)%	0.7	(2.0)	107.7	1.9	11.7	(9.4)	7.1	7.1	4.7
1966-1973	49.0%	29.3	18.3	15.3	22.9	7.3	25.7	8.6	9.5	16.6
1973-1974	(24.6)%	11.0	65.8	137.2	42.7	(6.9)	39.5	11.2	10.2	31.5

Exhibit IV-16b

SOURCES OF FUNDS

Privately Owned Class A&B Electric Utilities in the United States
Electric and Gas Departments

1960-1974

(percentages of total funds)

(1) Year	External Funds					Internal Funds			(10) Total
	(2) Common Stock	(3) Preferred Stock	(4) Long-Term Debt	(5) Short-Term Debt	(6) Total	(7) Retained Earnings	(8) Deferred Taxes	(9) Depreciation and Amortization	
1960	3.5	5.5	40.2	0.2	49.4	12.8	5.1	32.7	50.6
1961	8.2	4.3	33.4	(0.8)	45.1	13.8	4.8	36.3	54.9
1962	6.3	5.3	35.4	(3.1)	43.9	15.3	4.2	36.6	56.1
1963	4.5	2.7	33.1	2.7	43.0	15.8	3.6	37.6	57.0
1964	6.6	4.4	28.5	1.3	40.8	17.7	3.0	38.4	59.2
1965	2.3	4.5	28.8	7.6	43.2	17.7	2.5	36.6	56.8
1966	2.6	4.5	41.0	3.3	51.4	15.2	2.0	31.5	48.6
1967	2.8	6.8	40.2	6.4	56.2	13.4	2.0	28.4	43.8
1968	4.4	6.3	41.4	6.5	58.6	11.4	2.2	27.8	41.4
1969	8.2	4.2	41.5	9.4	63.3	10.5	1.8	24.4	36.7
1970	12.1	9.9	48.8	(0.9)	69.9	8.2	1.2	20.7	30.1
1971	15.3	13.7	40.3	1.0	70.3	8.0	2.2	19.5	29.7
1972	16.5	15.3	31.4	1.0	64.2	9.6	5.0	21.2	35.8
1973	16.2	10.3	32.2	6.9	65.6	9.1	4.6	20.7	34.4
1974	9.4	8.7	40.6	12.4	71.2	6.4	4.8	17.5	28.8

Source: Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, 1974; Column 5: Federal Power Commission

Exhibit IV-17

CAPITAL STRUCTURE

Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments

1960-1974

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Common Equity				
Year	Total Capitalization (thousands)	Common Stock and Surplus %	Retained Earnings %	Total (3)+(4) %	Preferred Stock %	Long-Term Debt %
1960	$ 39,840,396	27.1	9.4	36.5	10.7	52.8
1961	41,743,950	27.2	9.6	36.8	10.4	52.8
1962	43,707,948	27.1	10.2	37.3	10.3	52.4
1963	45,335,842	27.7	10.2	37.9	10.0	52.1
1964	47,499,663	27.8	10.8	38.6	9.6	51.8
1965	49,505,579	27.5	11.5	39.0	9.5	51.5
1966	53,053,664	26.1	12.1	38.2	9.5	52.3
1967	57,261,741	25.2	12.2	37.4	9.6	53.0
1968	62,267,112	24.1	12.5	36.6	9.6	53.8
1969	67,949,800	23.4	12.6	36.0	9.4	54.6
1970	76,482,105	23.2	12.2	35.4	9.8	54.8
1971	86,178,101	23.3	11.8	35.1	10.7	54.2
1972	97,080,398	23.5	11.6	35.1	11.8	53.1
1973	108,347,163	24.2	11.4	35.6	12.1	52.3
1974	121,686,000	23.9	10.9	34.8	12.2	53.0

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974.

Exhibit IV-18

LONG- AND SHORT-TERM DEBT

Privately Owned Class A&B Electric Utilities in the United States
Electric and Gas Departments

1960-1974

(1) Year	(2) Total Debt (thousands)	(3) Annual % Change	(4) Long-Term Debt (thousands)	(5) % of Total Debt (4)÷(2)	(6) Annual % Change	(7) Short-Term Debt (thousands)	(8) % of Total Debt (7)÷(2)	(9) Annual % Change
1960	21,539,601	6.0%	21,034,917	97.7%	8.9%	504,684	2.3%	1.9%
1961	22,475,643	4.3	22,028,356	98.0	4.7	447,287	2.0	(11.4)
1962	23,270,077	3.5	22,912,188	98.5	4.0	357,889	1.5	(20.0)
1963	24,099,215	3.6	23,631,832	98.1	3.1	467,383	1.9	30.6
1964	25,107,947	4.2	24,588,965	97.9	4.1	518,982	2.1	11.0
1965	26,369,789	5.0	25,502,451	96.7	3.7	867,338	3.3	67.1
1966	28,781,345	9.1	27,728,493	96.3	8.7	1,052,852	3.7	21.4
1967	31,838,701	10.6	30,358,468	95.4	9.5	1,480,233	4.6	40.6
1968	35,480,498	11.4	33,519,443	94.5	10.4	1,961,055	5.5	32.5
1969	39,877,367	12.4	37,071,763	93.0	10.6	2,805,604	7.0	43.1
1970	44,639,345	11.9	41,937,530	93.9	13.1	2,701,815	6.1	(3.7)
1971	49,545,612	11.0	46,707,745	94.3	11.4	2,837,867	5.7	5.0
1972	54,523,145	10.0	51,553,127	94.6	10.4	2,970,018	5.4	4.7
1973	60,821,246	11.6	56,763,481	93.3	10.1	4,057,765	6.7	36.6
1974	71,135,000	17.0	64,499,000	90.7	13.6	6,636,000	9.3	63.5
1965-1974	Average Annual Increase	8.1%						
	Ten-Year Average	11.0%						

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974.

Exhibit IV-19

MARKET VALUE VS. BOOK VALUE AND PRICE/EARNINGS COMPARISONS

Moody's Public Utility Index

1960-1974

(1)	(2) Moody's Public Utility Index	(3)	(4)	(5)
Year	Market Value	Book Value	Market to Book Ratio (2)÷(3)	Year-end Price/Earnings Ratio
1960	76.82	41.20	1.86	18.6
1961	99.32	42.95	2.31	22.9
1962	96.49	44.88	2.15	20.4
1963	102.31	47.91	2.14	20.5
1964	115.54	50.69	2.28	21.4
1965	114.86	52.68	2.18	19.4
1966	105.99	54.53	1.94	16.8
1967	98.19	57.53	1.71	14.7
1968	104.04	60.97	1.66	15.5
1969	84.62	63.90	1.32	12.2
1970	88.59	67.75	1.31	12.9
1971	85.56	70.24	1.22	12.0
1972	83.61	75.05	1.11	10.8
1973	60.87	76.84	0.79	8.1
1974	41.17	79.94	0.52	5.4

Source: Moody's Public Utility Manual, 1975 edition, pages 11-13

Exhibit IV-20

EXTERNAL SOURCES OF FUNDS

Privately Owned Class A&B Electric Utilities in the United States Electric and Gas Departments

1960-1974

Year	Common Stock as % of External Funds	Preferred Stock as % of External Funds	Debt as % of External Funds	External Funds as % of Total Funds
1960	7.1	11.2	81.7	49.2
1961	17.9	9.4	72.8	45.9
1962	13.4	11.3	75.3	47.0
1963	11.2	6.7	82.1	40.3
1964	16.7	11.1	72.2	39.5
1965	6.5	12.6	80.9	35.6
1966	5.4	9.4	85.2	48.1
1967	5.6	13.7	80.7	49.8
1968	8.4	12.1	79.5	52.1
1969	15.2	7.8	77.0	53.9
1970	17.1	14.0	68.9	70.8
1971	22.1	19.8	58.1	69.3
1972	26.1	24.2	49.7	63.2
1973	27.6	17.5	54.9	58.7
1974	16.0	14.8	69.2	58.7

Source: Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, 1974

Exhibit IV-21

YIELD AND YIELD SPREADS OF Aa UTILITY BONDS
1960-1975
(Average for Year)

Year	Aa New Utility Deferred Call	Long-Term Government Bonds	Yield Spread (Basis Points
	%	%	
1960	4.73	4.07	+66
1961	4.52	3.94	+58
1962	4.36	4.06	+30
1963	4.33	4.08	+25
1964	4.46	4.21	+25
1965	4.57	4.26	+31
1966	5.45	4.72	+73
1967	5.87	4.93	+93
1968	6.61	5.40	+121
1969	7.75	6.28	+147
1970	8.83	6.82	+301
1971	7.74	6.12	+162
1972	7.45	5.95	+150
1973	7.74	7.00	+74
1974	9.27	7.98	+129
1975	9.51	8.25	+126

Source: Salomon Bros. Analytical Record, December 1975.

Exhibit IV-22

INTEREST CHARGE COVERAGE

Privately Owned Class A&B Electric Utilities in the United States Electric Department

1960-1974

(dollars in millions)

(1) Year	(2) Income Before Interest & Taxes	(3) Interest*	(4) % Coverage
1960	$ 3,535	$ 692	5.1
1961	3,772	735	5.1
1962	4,016	779	5.2
1963	4,207	845	5.0
1964	4,486	843	5.3
1965	4,685	890	5.3
1966	4,969	986	5.0
1967	5,183	1,132	4.6
1968	5,588	1,341	4.2
1969	5,904	1,642	3.6
1970	5,964	2,044	2.9
1971	6,454	2,401	2.7
1972	7,366	2,774	2.7
1973	8,391	3,264	2.6
1974	9,058	4,197	2.2

*Total interest charges, including that on short-term obligations

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974

Exhibit IV-23

EMBEDDED INTEREST RATE ON LONG-TERM DEBT

Privately Owned Class A&B Electric Utilities in the United States
Electric Department

1960-1974

(dollars in millions)

(1) Year	(2) Interest	(3) Average Long-Term Debt	(4) Embedded Rate (%)
1960	$ 668	$ 18,466	3.62
1961	705	19,453	3.62
1962	757	20,290	3.73
1963	819	20,991	3.90
1964	813	21,698	3.75
1965	857	22,515	3.81
1966	933	23,926	3.90
1967	1,061	26,155	4.06
1968	1,240	28,875	4.29
1969	1,473	32,052	4.60
1970	1,874	36,033	5.20
1971	2,236	40,627	5.50
1972	2,613	45,254	5.77
1973	2,984	50,163	5.95
1974	3,606	56,527	6.38

Source: Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, and 1973; TBS estimate

Exhibit IV-24

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION VS. CAPITAL EXPENDITURES

Privately Owned Class A&B Electric Utilities in the United States
Electric Department

1960-1974

(1) Year	(2) AFDC* (millions)	(3) Capital Expenditures (millions)	(4) Percentage (2) ÷ (3)	(5) Net Income After Preferred Dividends (millions)	(6) AFDC* as Percent Of Column (5) (2) ÷ (5)
1960	$ 90	$ 3,331	2.70	$1,473	6.0
1961	76	3,256	2.33	1,550	4.9
1962	80	3,154	2.54	1,702	4.5
1963	69	3,319	2.08	1,786	3.6
1964	72	3,551	2.03	2,001	3.6
1965	84	4,027	2.09	2,171	3.8
1966	114	4,932	2.31	2,319	4.9
1967	171	6,120	2.79	2,440	7.0
1968	259	7,140	3.63	2,511	10.3
1969	383	8,294	4.62	2,682	14.3
1970	548	10,145	5.40	2,810	19.8
1971	770	11,894	6.47	3,062	25.6
1972	1,011	13,385	7.55	3,520	29.4
1973	1,187	14,907	7.96	3,948	31.8
1974	1,491	16,350	9.12	3,885	38.4

*Allowance for Funds During Construction

Source: Columns (2) and (5): Statistics of Privately Owned Electric Utilities in the United States, Federal Power Commission, 1967, 1972, 1973, and preliminary 1974.

Column (3): Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, 1974.

Exhibit IV-25

ELECTRIC UTILITY NEW PLANT AND EQUIPMENT EXPENDITURES VS. ALL INDUSTRY PLANT AND EQUIPMENT EXPENDITURES

Privately Owned Electric Utilities in the United States

1960-1974

(dollars in billions)

(1) Year	(2) Electric Utility Capital Expenditures	(3) All Industry Expenditures	(4) Percent (2) ÷ (3)
1960	$ 3.33	$ 34.6	9.62
1961	3.26	32.9	9.91
1962	3.15	36.6	8.61
1963	3.32	38.2	8.69
1964	3.55	43.7	8.12
1965	4.03	52.3	7.71
1966	4.93	61.1	8.07
1967	6.12	61.9	8.24
1968	7.14	66.5	10.74
1969	8.29	74.0	11.20
1970	10.15	75.1	13.52
1971	11.89	77.1	15.42
1972	13.39	87.1	15.37
1973	14.91	103.3	14.43
1974	16.35	111.7	14.64

Source: Column (2): Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1974

Column (3): Board of Governors of the Federal Reserve System, Flow of Funds Statistics

Exhibit IV-26

NET FINANCING ELECTRIC UTILTITY INDUSTRY VS. NON-FINANCIAL BUSINESS CORPORATIONS

Privately Owned Electric Utilities in the United States
Electric & Gas Departments

1960-1974

(billions of dollars)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Equity			Long-Term Debt			Short-Term Debt			Total		
Year	Non-Financial Business Corporation	Total Electric Utilities	3 ÷ 2 (%)	Non-Financial Business Corporation	Total Electric Utilities	6 ÷ 5 (%)	Non-Financial Business Corporation	Total Electric Utilities	9 ÷ 8 (%)	Non-Financial Business Corporation	Total Electric Utilities	12 ÷ 11 (%)
1960	1.5	.3	20	6.0	1.5	25	4.3	*	1	11.9	1.8	15
1961	2.2	.4	18	8.6	1.2	14	1.4	*	(1)	12.3	1.6	13
1962	.4	.4	100	9.1	1.4	15	3.0	(.1)	(3)	12.5	1.7	14
1963	-.6	.3	--	8.8	1.3	15	3.9	.1	3	12.1	1.7	14
1964	1.3	.5	38	7.6	1.2	16	5.6	.1	2	14.5	1.8	12
1965	-.1	.3	--	9.3	1.3	14	11.2	.4	4	20.4	2.0	10
1966	1.1	.4	36	14.4	2.3	16	9.9	.2	2	25.4	2.9	11
1967	2.2	.6	27	19.2	2.7	14	8.2	.4	5	29.6	3.7	13
1968	-.2	.8	--	18.6	3.0	16	13.2	.5	4	31.5	4.3	14
1969	3.4	1.1	32	16.6	3.7	22	18.8	.8	4	38.9	5.6	14
1970	5.7	2.5	44	24.7	5.7	23	8.9	(.1)	(1)	39.5	8.1	21
1971	11.4	3.9	34	30.1	5.5	18	5.0	.1	2	46.8	9.5	20
1972	10.9	4.4	40	28.3	4.3	15	16.0	.2	1	55.3	8.9	16
1973	7.4	4.2	57	27.1	5.1	19	32.6	1.1	3	67.2	10.4	15
1974	4.1	3.8	93	32.2	8.4	26	40.9	2.6	6	77.2	14.8	19

*less than .05

Source: Federal Reserve Board, Flow of Funds Statistics; Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1974; Federal Power Commission

Exhibit IV-27

GROSS EQUITY FINANCING ELECTRIC UTILITY INDUSTRY VS. TOTAL PRIVATE SECTOR

Privately Owned Electric Utilities in the United States
Electric and Gas Departments

1960-1974

(dollars in billions)

	Common Stock			Preferred Stock		
(1) Year	(2) Total Private Sector	(3) Total Electric Utilities	(4) (3) ÷ (2) %	(5) Total Private Sector	(6) Total Electric Utilities	(7) (6) ÷ (5) %
1960	$ 1,664	$ 130	7.8	$ 409	$ 201	49.1
1961	3,294	294	8.9	450	153	34.0
1962	1,314	243	18.5	422	201	47.6
1963	1,011	181	17.9	343	108	31.5
1964	2,679	272	10.2	412	184	44.7
1965	1,547	105	6.9	725	208	28.7
1966	1,939	148	7.6	574	253	44.1
1967	1,959	185	9.4	885	453	51.2
1968	3,946	326	8.3	637	461	72.4
1969	7,714	744	9.6	682	381	55.9
1970	7,240	1,411	19.5	1,290	1,147	82.5
1971	10,459	2,063	19.7	3,683	1,851	50.3
1972	9,914	2,281	23.0	3,372	2,104	62.4
1973	7,648	2,552	33.4	3,375	1,629	48.3
1974	4,017	1,951	48.6	2,224	1,809	81.3

Note: The entries in columns (2) and (5) represent gross private sector financing. This includes funds raised by financial intermediaries, and has no offsetting entries for reduction in equity, capital through mergers, acquisitions, liquidations, etc.

Source: Columns (2) and (5): Business Statistics 1973 and Survey of Current Business, U.S. Department of Commerce, October 1975.

Columns (3) and (6): Statistical Yearbook of the Electric Utility Industry for 1972, Edison Electric Institute, 1974.

Exhibit IV-28

DOWNGRADING OF ELECTRIC UTILITY SECURITIES
1965-July 1974

(1) Year	(2) Total Actions	(3) Aaa to Aa	(4) Aa to A	(5) A to Baa	(6) Baa to Ba	(7) Suspended
1965	0	--	--	--	--	--
1966	8	2	6	--	--	--
1967	0	--	--	--	--	--
1968	6	3	3	--	--	--
1969	6	2	4	--	--	--
1970	4	2	2	--	--	--
1971	5	1	1	3	--	--
1972	4	1	1	2	--	--
1973	2	--	2	--	--	--
1974	31	1	12	11	1	6
Total	66	12	31	16	1	6

Source: Moody's Public Utility Manual taken from a compilation by the Office of Accounting and Finance, Federal Power Commission.

Exhibit IV-29

ISSUE AND RECENT MARKET PRICES--
15 RECENT ELECTRIC UTILITY BOND ISSUES

Rating	Issue Date (1974)	Issue	Offered Price	Yield	Nov. 22, 1974 or Last Trade	Yield
Aaa	10/2	Texas P&L 10-1/8-2004	100(plus Int.)	10.125	107	9.42
Aa	9/5	Illinois Power 10-1/2-2004	100(plus Int.)	10.50	106-3/4	9.80
Aa	9/11	Northern Indiana P.S. 10.40-2004	100	10.40	106	9.78
Aa	9/12	Baltimore G&E 10-1/8-1983	99-5/8	10.19	103-1/2	9.54
Aa	10/3	Public Service Elec.& Gas. 12-2004	100(plus Int.)	12.00	108-1/2	11.02
Aa	10/2	Pa. P&L 10-1/8-82	100(plus Int.)	10.125	104-3/8	9.34
Aa	10/31	So.Calif.Edison 9-1981	99-1/2(plus Int.)	9.10	103-3/4-101-1/4	8.52
Aa	11/14	West Penn.Power 9-1/4-2004	101(plus Int.)	8.88	96-1/2-97	9.58
Aa	11/7	Long Island Lighting 9-1/4-1982	100(plus Int.)	9.25	100-100-1/2	9.21
A	10/17	Philadelphia Electric 11-1980	100(plus Int.)	11.00	102-1/2	10.93
A	10/22	Dayton P&L 10-1/8-1981	100(plus Int.)	10.125	100-1/2-101-1/4	9.95
A	10/30	Louisiana P&L 9-1/2-1981	101(plus Int.)	9.30	100-3/4	9.35
Baa	10/29	Ohio Power 12-1/8-1981	100-5/8(plus Int.)	12.00	103 Bid	11.49
Baa	10/30	Jersey Central P&L 12-3/8-1979	101-3/4	11.90	103-1/8	11.54
Baa	11/7	Puget Sound P&L 10-3/4-1983	100-1/4	10.70	101-1/2	10.49

Source: Moody's Public Utility Weekly Supplements, 1974 Issues.
Wall Street Journal, November 25, 1974

Exhibit IV-30

PROJECTIONS OF EXTERNAL FINANCING REQUIREMENTS FOR INVESTOR-OWNED ELECTRIC UTILITIES

1975-1985

(billions of 1975 dollars)

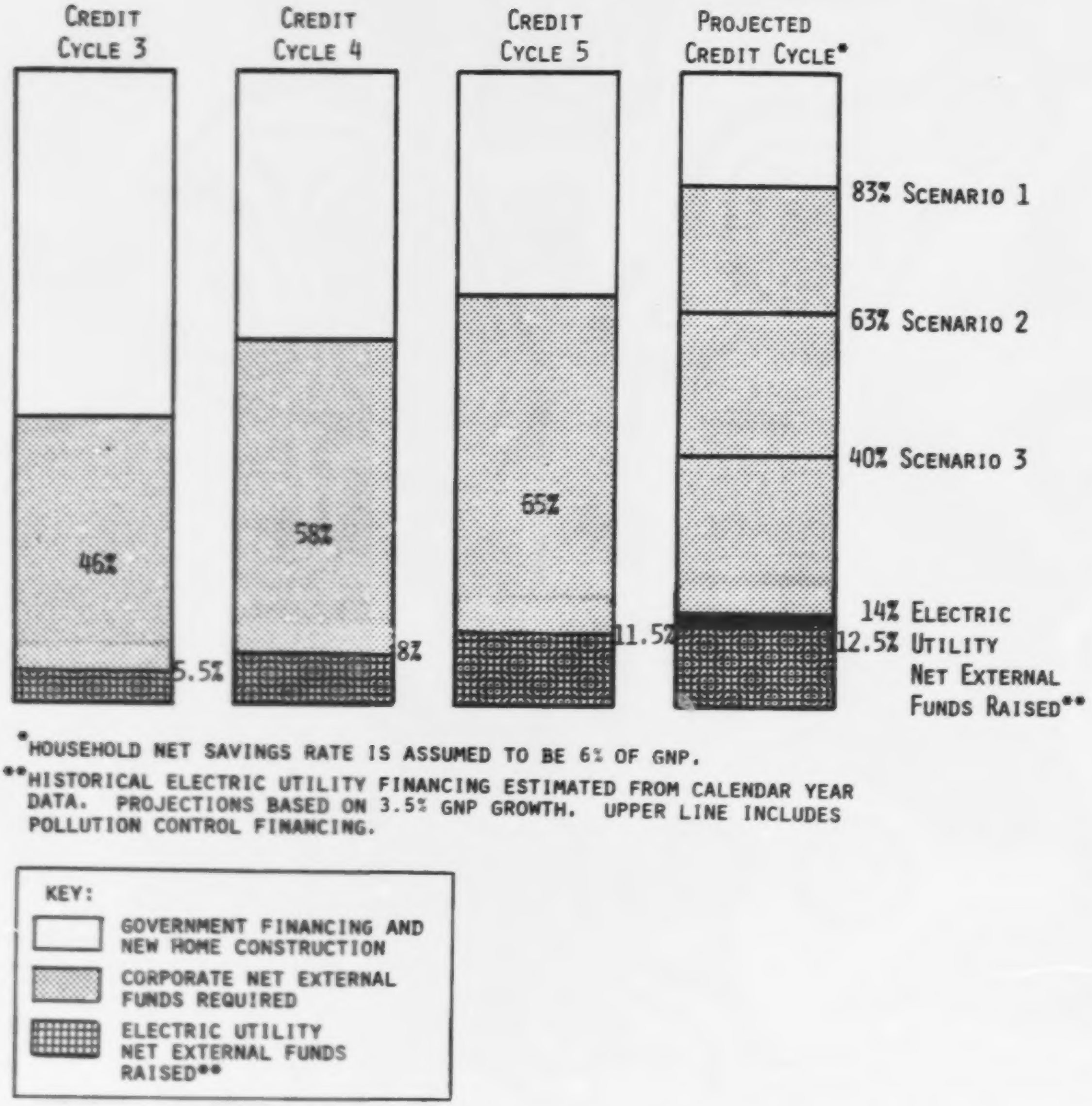
	Before Consideration of Pollution Control	Required for Pollution Control	Total
1975	11.7	1.6	13.3
1976	10.9	1.9	12.8
1977	12.1	2.1	14.2
1978	12.2	2.5	14.7
1979	12.9	2.7	15.6
1980	13.2	2.2	15.4
Subtotal	73.0	13.0	86.0
1981	12.8	1.4	14.2
1982	14.2	1.0	15.2
1983	15.5	1.1	16.6
1984	18.0	1.2	19.2
1985	21.5	1.6	23.1
Subtotal	82.0	6.3	88.3
Total	155.0	19.3	174.3

Note: Results assume 14 percent return on equity.

Source: PTm (Electric Utilities)

EXHIBIT IV-31

ILLUSTRATION OF ELECTRIC UTILITY AND CORPORATE NET EXTERNAL FUNDS REQUIRED AS PERCENT OF NET SAVINGS IN THE HOUSEHOLD SECTOR



*HOUSEHOLD NET SAVINGS RATE IS ASSUMED TO BE 6% OF GNP.

**HISTORICAL ELECTRIC UTILITY FINANCING ESTIMATED FROM CALENDAR YEAR DATA. PROJECTIONS BASED ON 3.5% GNP GROWTH. UPPER LINE INCLUDES POLLUTION CONTROL FINANCING.

Exhibit IV-32

INTEREST COVERAGE PROJECTIONS BEFORE POLLUTION CONTROL FINANCING FOR INVESTOR-OWNED ELECTRIC UTILITIES

(billions of 1975 dollars)

	1980	1985
Allowance for Funds During Construction (AFDC)	2.3	3.6
Earnings Before Interest[1] and Taxes	20.6	28.7
Interest on Long-Term Debt	7.3	10.6
State and Federal Income Taxes	4.7	6.6
Preferred Dividends	1.2	1.9
Earnings Available to Common Stock	7.3	9.8
Interest Coverage:		
Including AFDC	2.8	2.7
Excluding AFDC	2.5	2.4

[1] on long-term debt only

Note: Results assume 14 percent return on equity.

Source: PTm (Electric Utilities)

Exhibit IV-33

INTEREST COVERAGE IMPLICATIONS OF POLLUTION CONTROL FINANCING FOR INVESTOR-OWNED ELECTRIC UTILITIES

WITH HISTORIC CAPITAL MIX

(billions of 1975 dollars)

	1980	1985
Allowance for Funds During Construction (AFDC)	2.6	3.8
Earnings Before Interest[1] and Taxes	22.3	31.2
Interest on Long-Term Debt	8.0	11.5
State and Federal Income Taxes	4.9	7.2
Preferred Dividends	1.4	2.0
Earnings Available to Common Stock	8.0	10.5
Interest Coverage:		
Including AFDC	2.8	2.7
Excluding AFDC	2.5	2.4

[1] on long-term debt only

Note: Results assume 14 percent return on equity.

Source: PTm (Electric Utilities)

Exhibit IV-34

INTEREST COVERAGE IMPLICATIONS OF POLLUTION CONTROL FINANCING FOR INVESTOR-OWNED ELECTRIC UTILITIES

WITH EQUITY ONLY

(billions of 1975 dollars)

	1980	1985
Allowance for Funds During Construction (AFDC)	2.6	3.8
Earnings Before Interest[1] and Taxes	23.4	32.9
Interest on Long-Term Debt	7.3	10.6
State and Federal Income Taxes	5.7	8.1
Preferred Dividends	1.4	2.0
Earnings Available to Common Stock	9.1	12.3
Interest Coverage:		
Including AFDC	3.2	3.1
Excluding AFDC	2.9	2.7

[1] on long-term debt only

Note: Results assume 14 percent return on equity.

Source: PTm (Electric Utilities)

Exhibit IV-35

INTEREST COVERAGE IMPLICATIONS OF POLLUTION CONTROL FINANCING FOR INVESTOR-OWNED ELECTRIC UTILITIES

WITH INDUSTRIAL REVENUE BONDS AT 6.6 PERCENT

(billions of 1975 dollars)

	1980	1985
Allowance for Funds During Construction (AFDC)	2.6	3.8
Earnings Before Interest[1] and Taxes	21.5	30.0
Interest on Long-Term Debt	8.2	11.9
State and Federal Income Taxes	4.7	6.6
Preferred Dividends	1.2	1.9
Earnings Available to Common Stock	7.3	9.6
Interest Coverage:		
Including AFDC	2.6	2.5
Excluding AFDC	2.3	2.2

[1] on long-term debt only

Note: Results assume 14 percent return on equity.

Source: PTm (Electric Utilities)

Exhibit IV-36

DETERMINANTS OF INTEREST COVERAGE RATIOS

	Cases				
	I (Base Case)	II (Higher Interest)	III (Lower Taxes)	IV (Higher ROE)	V (Less Debt)
Assumptions					
Capital Structure					
Debt	$600	$600	$600	$600	$550
Preferred	100	100	100	100	100
Common	300	300	300	300	350
Capital Costs					
Debt	6%	10%	10%	10%	10%
Preferred	6%	6%	6%	10%	10%
Common	12%	12%	12%	16%	16%
Tax Rate	25%	25%	0%	0%	0%
Income Statement					
Required Earnings Before Interest and Taxes	$ 92	$116	$102	$118	$121
Interest	36	60	60	60	55
Earnings Before Taxes	$ 56	$ 56	$ 42	$ 58	$ 66
Tax	14	14	0	0	0
Net Income	$ 42	$ 42	$ 42	$ 58	$ 66
Preferred Dividends	6	6	6	10	10
Income Available for Common	$ 36	$ 36	$ 36	$ 48	$ 56
Interest Coverage Ratio	2.56	1.93	1.70	1.97	2.20

Exhibit IV-37

THE IMPACT OF AFDC ON INTEREST COVERAGE RATIOS

	Cases	
	Ia (Base Case With No AFDC)	Ib (Base Case With High AFDC)
Income Statement		
Operating Income	$ 92	$ 62
Other Income (AFDC)	-	30
Required Earnings Before Interest and Taxes	$ 92	$ 92
Interest	36	36
Earnings Before Taxes	$ 56	$ 56
Tax	14	14
Net Income	$ 42	$ 42
Preferred Dividends	6	6
Income Available for Common	$ 36	$ 36
Income as Defined for Coverage[1]	$ 92	$ 68
Interest Coverage Ratio	2.56	1.89

---

[1] *Operating income plus other income up to 10 percent of operating income.*

APPENDIX IV-A

THE EFFECTS OF ISSUING STOCK AT DIFFERENT MARKET PRICES RELATIVE TO BOOK VALUES

The following cases illustrate the earnings per share consequences of issuing common stock at prices above and below book value. For simplicity, we shall assume throughout that the rate of return r_e allowed by regulators is 12 percent on the common equity base at the beginning of any year and that the dividend payout ratio b is 70 percent. Assuming for the moment that the industry or any given utility issues no stock, the industry's total earnings and dividends will grow at a rate g which is 3.6 percent. A 12 percent return and a 30 percent retention of this amount (because dividends are 70 percent of earnings) means that the industry's common equity grows 3.6 percent per year, that earnings grow 3.6 percent (because the percentage return on equity is constant), and that dividends grow at 3.6 percent (because the payout ratio is constant). There is a well-known formula for stock prices in constant growth situations of this sort which can be written as:

$$P_0 = \frac{D_0}{k_e - g},$$

Where:

P_0 = stock price at time 0 relative to book value;

D_0 = dividends at time 0 relative to book value; and

Preceding page blank

k_e = investors' required rate of return on investment in stock of this risk class.

Dividends at time 0 can in turn be expressed as a fraction of book value as follows:

$$D_0 = E_0 \times b,$$

Where:

E_0 = earnings at time 0 relative to book value

Earnings relative to book value can in turn be written simply as:

$$E_0 = r_e,$$

Where:

r_e = the allowed rate of return on equity.

If the required rate of return is 10 percent or 15 percent, then the industry's market price relative to book value is 1.313 or 0.737, respectively. Given that we have assumed no new issues of common stock, these ratios hold on a per share basis as well.

Let us consider what happens if the industry's capital expenditure requirements (or desires) are such as to necessitate (or prompt) the one-time issuance of common stock. For simplicity, we shall first assume that investors either do not anticipate the issuance of common stock or do not react to its predictable consequences; this will simplify the calculation of the number of shares required to raise a given dollar amount of equity capital. The effect of correct anticipations will be discussed second. To make our points clear, let us consider two illustrative cases. In the first, let us assume that investors are willing to settle for a 10 percent return for investing in the industry's common equity. In the second, perhaps either because the risks have increased or because inflation has shifted the general levels of nominal (current dollars) required rates of return upward, let us assume investors demand a 15 percent return. We shall also assume initially that the industry's need for common equity capital over time is just met by retained earnings in all years except one. As above, with the exception of the year of the stock issue, this means that required equity grows by 3.6 percent per year, and that earnings, earnings per share, and dividends per share grow at 3.6 percent per year.

CASE 1: IF ALLOWED RETURNS ON EQUITY ARE GREATER THAN INVESTORS' REQUIRED RATES OF RETURN, THEN EARNINGS PER SHARE, DIVIDENDS PER SHARE, AND MARKET PRICES INCREASE WITH INCREASING GROWTH.

Assumptions

Initial Equity	$S_0 = \$1,000,000$
Allowed Return on Equity	$r_e = 12\%$
Earnings	$E_0 = \$120,000$
Payout Ratio	$b = .7$
Dividends	$D_0 = b \times E_0 = \$84,000$
Retained Earnings as Function of Profit to Common	$a = (1-b) = .3$

Growth in Earnings and Dividends	$g = a \times r_e = .036$
Shares Outstanding	$n_0 = 100{,}000$
Return Required by Investors	$k_e = 10\%$
Market Price Per Share	$p_0 = \dfrac{D_0}{(k_e - g)n_0} = \$13.13$

The market price of shares is $13.13 if the shares are valued at the present value at 10 percent of an infinite stream of dividends. This price contrasts with a book value of $10 per share.

Suppose now that there is an external equity financing requirement of $100,000 which arises too quickly for the market to anticipate and hence which is financed at $13.13 per share.

Required Equity Issue	$\Delta S = \$100{,}000$
Number of Shares Issued	$\Delta n = \dfrac{\Delta S}{p_o} = 7{,}619$ shares
New Equity Balance	$S_1 = \$1{,}100{,}000$
New Earnings	$E_1 = \$\ 132{,}000$
New Dividends	$D_1 = \$\ 92{,}400$
New Total Shares Outstanding	$n_1 = 107{,}619$
New Earnings Per Share	$e_1 = E_1 \div n_1 = \$1.23$
New Dividends Per Share	$d_1 = D_1 \div n_1 = \$0.86$
New Market Price Per Share	$p_1 = \dfrac{d_1}{k_e - g} = \$13.42$

The effect of the increased equity investment is to raise earnings, dividends, and market price per share by 2.2 percent. In this instance, because the pre-issue stock price did not reflect the opportunity to invest $100,000 at a rate of return above that demanded by the market, both the old shareholders and the new purchasers of stock received a $0.29 per share "windfall" gain.

If investors correctly anticipate the future need for common equity financing, then the pre-financing prices will adjust so as to drive out the post-financing windfall gain (or loss) to investors. In Case 1, pre-financing prices reflect the capitalization of the expected post-financing dividend stream at 10 percent, thereby boosting the pre-financing price upward and reducing the number of shares required to raise $100,000 in new capital. Thus, new investors purchase their shares at a price that holds their return on investment to 10 percent; the benefits of the industry's having an opportunity to invest at above-market returns all accrue to the original shareholders. Of course, if after the date of purchase of the new shares the industry unexpectedly has yet another opportunity to invest equity over and above retained earnings at a favorable rate, the "new" investors would share in the second round of windfall gains. If both the first and the second opportunity were correctly anticipated at the time of the first issue, however, the stock would have risen in market price so as to reflect all the benefits of both opportunities and to provide both the first and second rounds of new purchases with only their required return on investment.

CASE 2: IF ALLOWED RETURNS ON EQUITY ARE LESS THAN INVESTORS' REQUIRED RATES OF RETURN, THEN EARNINGS PER SHARE, DIVIDENDS PER SHARE, AND MARKET PRICES DECREASE WITH INCREASING GROWTH.

Assumptions

Same as Case 1 except:

$k_e = 15\%$

$$P_0 = \frac{D_0}{(k_e - g)n_0} = \$7.37$$

The market price an investor requiring a 15 percent return will pay for a $10 book value share is $7.37.

Suppose again that a sudden requirement for external equity financing of $100,000 arises too quickly for the market to anticipate and, hence, is financed at $7.37 per share.

$\Delta S = \$100,000$

$E_1 = \$132,000$

$$\Delta n = \frac{\Delta S}{P_0} = 13,572 \text{ shares}$$

$n_1 = 113,572$

$e_1 = E_1 \div n_1 = \$1.16$

$$d_1 = D_1 \div n_1 = \$0.81$$

$$p_1 = \frac{d_1}{k_e - g} = \$7.14$$

Selling stock to meet capital needs when the market price is below book drives earnings per share, dividends per share, and market price per share to lower levels.

As in Case 1, the effect of investors' correctly anticipating the industry's investment of inadequate rates of return is to accentuate the effect of the simplistic examples. If anticipated, the Case 2 investment would be reflected in pre-issue stock prices less than $7.37, necessitating the issuance of more than 13,572 shares to raise $100,000 and thereby exacerbating the investment's damage to earnings and dividends per share.

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

VOLUME V

REGIONAL IMPACT PROJECTIONS

MAY 1976

VOLUME V

TABLE OF CONTENTS

Page

List of Exhibits (V-iii)

Chapter

1 INTRODUCTION AND SUMMARY OF REGIONAL IMPACT PROJECTIONS V-1

2 REGIONAL BASELINE PROJECTIONS V-5
Operating Projections V-7
Financial Projections V-12

3 REGIONAL POLLUTION CONTROL IMPACTS V-19
Methodology V-19
Impact of Pollution Control Compliance Measured by Consumer Charges V-21
Impacts Projected Region by Region V-23
Summary of Regional Capital Expenditures and Operating and Maintenance Expenses V-41

Appendix

V-A New England (Region I) V-63
V-B Middle Atlantic (Region II) V-69
V-C East North Central (Region III) V-75
V-D West North Central (Region IV) V-81
V-E South Atlantic (Region V) V-87
V-F East South Central (Region VI) V-93
V-G West South Central (Region VII) V-99
V-H Mountain (Region VIII) V-105
V-I Pacific (Region IX) V-111

VOLUME V

LIST OF EXHIBITS

Exhibits

V-1 Estimated Installed Generating Capacity; 1972 Baseline Year

V-2 Regional Historical Fossil Trends; Percent of Generation

V-3 Ultimate Customer Kilowatt-hour Usage and Growth Rates, 1960-1974

V-4 Regional Projection; Thousands of Customers and Growth Rates

V-5 Electric Customers as a Percentage of National Population, 1960-1973

V-6 Regional Historical and Projected Population, 1960-1990

V-7 Regional Generation Not Sold To Ultimate Customer, 1960-1974

V-8 Regional Baseline Summary Table; Regional Comparison: Capacity Mix by Prime Mover, 1975 (kw)

V-9 Regional Baseline Summary Table; Regional Comparison: Generation Mix by Prime Mover, 1975 (kwh)

V-10 Regional Baseline Summary Table; Regional Comparison: Capacity Mix by Prime Mover, 1980 (kw)

V-11 Regional Baseline Summary Table; Regional Comparison: Generation Mix by Prime Mover. 1980 (kwh)

V-12 Regional Baseline Summary Table; Regional Comparison: Capacity Mix by Prime Mover, 1985 (kw)

V-13 Regional Baseline Summary Table; Regional Comparison: Generation Mix by Prime Mover, 1985 (kwh)

V-14 Regional Coal Capacity by In-Service Year; For Compliance with Clean Air Act, 1985

V-15 Regional Baseline Projections; Summary of Cumulative Additions (Adjusted FPC Announcements), 1975-1980

Preceding page blank

Exhibit

V-16 Regional Baseline Projections; Summary of Cumulative Additions, 1981-1985

V-17 Regional Baseline Projections; Summary of Assumptions, 1975

V-18 Regional Baseline Projections; Summary of Assumptions, 1980

V-19 Regional Baseline Projections; Summary of Assumptions, 1985

Appendices

Appendices V-A through V-I, as listed in the Table of Contents, contain the following exhibits for each region:

1. Capacity Report
2. Financial Baseline Projections
3. Coal Capacity: Coverage for Compliance with Clean Air Act
4. Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
5. Impacts of Air and Water

CHAPTER 1

INTRODUCTION AND SUMMARY OF REGIONAL IMPACT PROJECTIONS

The financial impacts of pollution control regulations are discussed in this volume as they occur on a region by region basis. Volumes I-IV have presented the baseline projections, impact projections and financial feasibility analysis at the national level as well as describing the underlying methodological approach which TBS has adopted. Those volumes provide the basis for the regional analysis. The purpose of this volume is to highlight the differences among regions both in the baseline projections and in the nature of the impacts likely to be incurred by each region. The chapters which follow discuss the most significant components of the operating and financial projections in the baseline as they are reflected in selected financial indicators.

Supplementary information appears in an appendix for each region; detailed exhibits on the baseline projections are included at the end of the volume.

SUMMARY OF FINANCIAL IMPACT ANALYSIS

The nine census regions[1] will be affected differentially by the implementation of the air and water pollution control regulations. The differences are primarily due to the amount of generating capacity which falls under the purview of the regulations. The differences in financial impact can best be illustrated through the ranges which will exist in additional capital expenditures and consumer charges by 1985.

---

[1] *Impact projections were not developed for the tenth census region, Alaska and Hawaii, see the footnote on page V-5.*

At the national level, it is expected that an increase of $25 billion will be required in capital expenditures by the end of the 1975-1985 decade. The impacts which will be incurred on a region-by-region basis range from a high of $5 billion in the East North Central region to a low of $350 million in New England. In between these extremes, the remaining regions will require additional capital expenditures in the following order: South Atlantic ($4.5),[2] West South Central ($3.4), East South Central ($3.4), West North Central ($2.6), Mountain ($2.5), Middle Atlantic ($2.5) and Pacific ($0.6).

While the absolute amount of capital expenditures needed in some regions is relatively high, that amount may not represent as significant a proportion of the total capital outlays as will be the case in regions starting out from a smaller base. The national average change in additional capital expenditures as a percent of baseline capital expenditures (without pollution control) is 10.5 percent. The range among regions is 2.4 percent (Pacific) to 17.6 percent (West South Central). Among the other regions, three are above the national average (Mountain, East South Central and East North Central) and four are below (West South Central, South Atlantic, Middle Atlantic and New England). Therefore, the degree of the impact varies depending upon whether the focus is on absolute capital requirements or on the magnitude of the change from a base level.

---

[2] *Billions of 1975 dollars. All costs and expenditures presented in this volume are in 1975 dollars unless otherwise noted.*

The same relationship exists regarding the degree of impact where consumer charges are used as a measure. The regions with the largest change do not necessarily have the highest total consumer charges. The range in increases in consumer charges because of pollution control is 1.3 to 11.1 percent by 1985, while the national average is 6.7 percent. On that basis, the overall ranking from most to least affected region would be: Mountain (11.1 percent), East South Central (10.2 percent), West North Central (10.1 percent), West South Central (9.0 percent), East North Central (8.3 percent), South Atlantic (5.2 percent), Middle Atlantic (4.1 percent, New England (1.8 percent), and Pacific (1.3 percent).

Apart from the direct financial impacts, the regional analysis has identified four key factors which cause the differences in impact among regions:

- the amount of coal capacity which will have been added by 1985 - West North Central, East North Central, East South Central, Mountain and West North Central will be adding the most;
- the amount of capacity which is affected by either the air regulations or the water regulations or both--New England for example is only slightly impacted by the air regulations while the South Atlantic is covered by both air and water regulations.
- the pollution control strategy selected to meet the regulations, for example the decision to use low sulfur coal or scrubbers to comply with the SO_2 regulation.

- the level of electricity usage per customer--which reflects among other things, the variations in the use of electrical heating instead of oil or gas.

The degree to which these factors occur in each region is further elaborated in Chapter 3.

In addition to the primary causal factors listed above, the basic characteristics of demand, capacity, costs and financial structure in each region provide the context for developing the impact projections. These basic characteristics and their financial implications have been projected for the 1975-1990 period and are summarized in Chapter 2 which follows.

CHAPTER 2

REGIONAL BASELINE PROJECTIONS

The regional baseline projections are essentially the translation of the national baseline projections into ten geographic subdivisions.[1] The approach used to develop the regional operating and financial projections for the baseline case parallels that used at the national level; that is, each region's projections were based upon the same computational logic and types of assumptions. Wherever possible, data were incorporated which specified differences among regions.

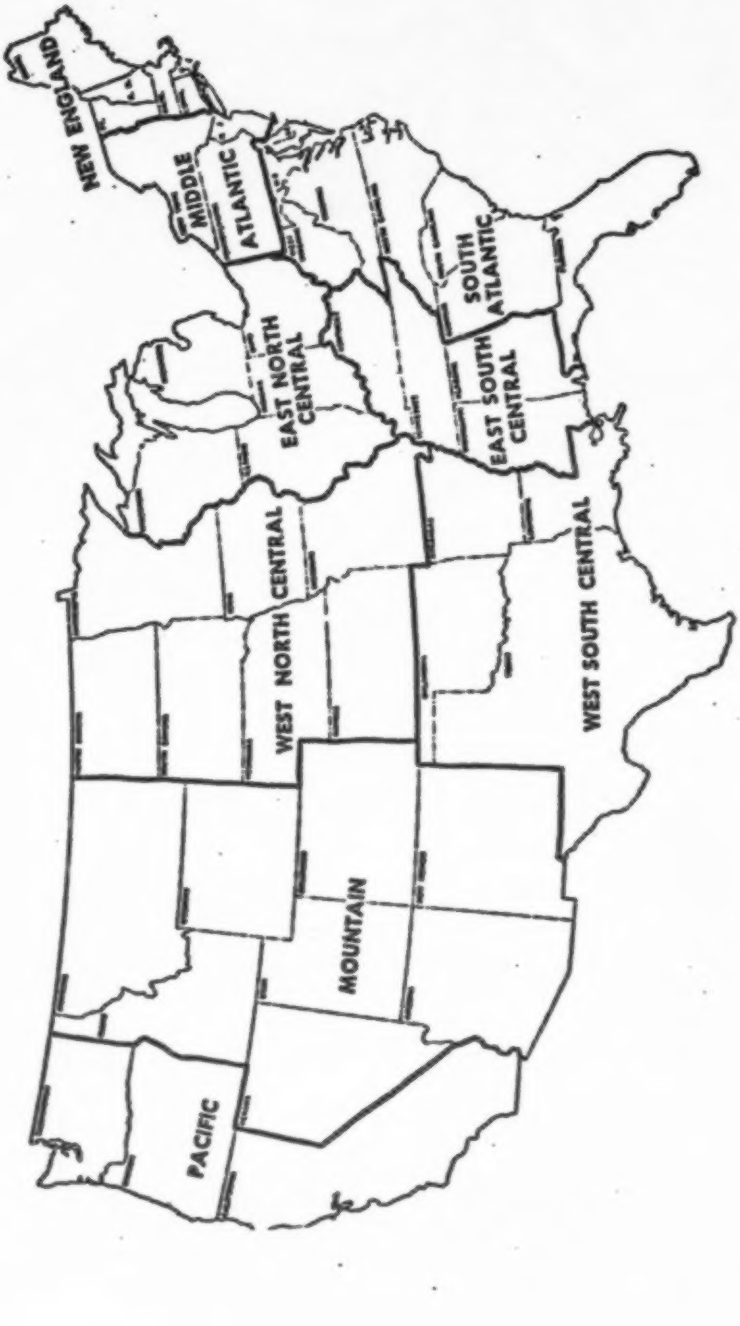
The categories of data used in the regional projections are described below.

(1) Data which were available uniquely for each region, such as additions to capacity (1975-1980), population growth, public and private ownership shares of capacity, use of flow through or normalized accounting procedures.

---

[1] *The geographic divisions used in this research effort are the ten Census regions designated by the Bureau of the Census. The states in each region are illustrated on Page 2. These ten regions vary somewhat from the states covered by each of the ten EPA regional offices and the regions used by the Federal Power Commission. The Census regions were selected because the FPC regions are not coterminous with state boundaries, and the electric utilities industry data as well as Census data is more compatible with the ten Census regions. Alaska (Region X) and Hawaii are not included in the impact analysis because of the unavailability of financial data.*

BUREAU OF THE CENSUS GEOGRAPHIC REGIONS


NEW ENGLAND
MIDDLE ATLANTIC
EAST NORTH CENTRAL
SOUTH ATLANTIC
EAST SOUTH CENTRAL
WEST NORTH CENTRAL
WEST SOUTH CENTRAL
MOUNTAIN
PACIFIC

(2) Data which were available uniquely for each region on an historic basis, but which could not be appropriately extrapolated into the future were used to compute ratios of each region's experience relative to the national figures. Fuel costs and other operating and maintenance costs are two examples.

(3) On certain topics no historical experience by region had been compiled and data was available only at the national level. In some cases, this data could be allocated by region. Energy conservation, for example, is a relatively new characteristic of demand which can be allocated by region on the basis of kilowatt hour usage per customer.

(4) And, finally, there were some data available only at the national level, such as capital costs and rates of retirement, which were applied uniformly to each region.

Exhibits V-1 through V-7 and V-17 through V-19 provide the regional information which was used as the basis for the operating and financial projections.

OPERATING PROJECTIONS

Demand

Estimates of demand growth are based upon each region's historical pattern of growth in number of customers and number of kilowatt-hours per customer. The historical growth pattern in usage per customer is then tempered by allocating a share of the national level of energy conservation. From these factors the sales to ultimate customers can be projected. The table below presents each region's projected annual growth rate (1975-1985) in kilowatt hours and the total projected sales for selected years.

ANNUAL DEMAND GROWTH RATE AND TOTAL SALES
BY REGION

	Annual Growth Rate*	Total Sales (billions kwh)		
	1975-1985 (%)	1975	1980	1985
New England	5.8	70.9	95.9	124.3
Middle Atlantic	4.6	236.1	301.6	370.1
East North Central	4.8	328.6	423.9	525.1
West North Central	5.4	102.8	136.0	173.2
South Atlantic	7.4	294.2	429.4	589.5
East South Central	3.5	150.3	182.9	224.5
West South Central	8.1	215.4	323.5	465.5
Mountain	5.7	70.8	107.4	138.3
Pacific	5.0	242.8	314.5	389.0
Alaska & Hawaii	6.4	6.8	9.6	12.7
National	5.7			

---

*based on kwh sales to ultimate customers

Source: PTm (Electric Utilities)

An examination of the patterns in the annual demand growth rate, by region, shows that about half the regions are above and half below the national average of 5.7 percent. Only two regions, West South Central (8.1 percent) and East South Central (3.5 percent), differ substantially in either direction, the other regions are clustered around the national growth rate. East South Central has had the highest usage of electricity per customer in the country (see Exhibit V-3) so the low growth rate over the 1975-1985 period may indicate a saturation of usage per customer. In addition, the slow growth rate reflects the historical pattern of a very slow rate of population growth and, therefore, a small rate of increase in new customers. The West South Central and South Atlantic regions are characterized by rapid population growth (Exhibit V-4), a high percentage of generation not sold (Exhibit V-7), and fairly rapid growth of usage per customer (Exhibit V-3). These three factors contribute to the high level of required additions to capacity which are discussed in the following section.

Capacity Additions

The sales levels of electricity dictate an amount of capacity sufficient to supply those levels. From a starting point of the actual level of installed capacity by fuel type in 1974, new additions are projected for each year. The procedure followed to project capacity additions for the short term (1975-1980) was the use of the modified Federal Power Commission's announced capacity additions for each region. The projections of capacity additions in 1981 and later are based on maintaining at least 20 percent reserve margin.[2] Projected capacity additions are largest for the South Atlantic, West South Central, and East North Central regions. These three regions are also among the four regions with the largest amount of existing capacity (see Exhibit V-11).

An examination of capacity additions by fuel type (Exhibits V-15, V-16) indicates the mix of fuels projected for the next decade. The coal share of total capacity and of additions is shown in the table below. Coal is not projected to be the dominant fuel in the capacity additions for the Northeast coastal regions (New England and Middle Atlantic) or the Pacific region. The regions in northern mid-continent (West North Central, East North Central, and Mountain) have traditionally been high users of coal and will continue to add coal capacity. However, the West South Central region, previously a heavy consumer of gas for electricity generation, will be placing more emphasis on coal the next decade. At the national level, slightly under one-half of the additions to capacity are expected to be coal based by 1985. Exhibits V-8, V-10, and V-12 summarize total capacity projections by fuel type. Other operating projections such as total generation and cumulative additions by fuel type appear in Exhibits V-9, V-11, V-13, V-15, and V-16.

---

[2] *Part One, Volume II of this report describes the approach which incorporates announced capacity additions, examines the consequences of various alternative approaches, and covers the questions of short-term, versus long-term projections for capacity additions.*

TOTAL CAPACITY AND CAPACITY ADDITIONS BY 1985

	Total Capacity (million kw)	Cumulative (1975-1985) Capacity Additions (million kw)	Total Coal Additions (million kw)
New England	28.9	11.2	-0-
Middle Atlantic	90.3	29.1	4.3
East North Central	125.9	49.1	29.3
West North Central	54.2	25.7	19.8
South Atlantic	141.0	65.1	24.3
East South Central	64.3	27.7	10.2
West South Central	114.2	63.6	39.0
Mountain	46.7	25.7	18.4
Pacific	83.8	30.4	4.7
Alaska & Hawaii	1.9	0.4	0.1
National	751.0	328.9	149.2

Source: Exhibits V-15, V-18, V-19; PTm (Electric Utilities).

Cost Factors

In projecting the financial implications of the operating conditions of the electric utility industry by region, two categories of costs must be considered: capital costs and operating costs. Capital costs for new capacity are applied uniformly across all regions and are fully discussed in Volume II. Operating costs are covered below.

Operating and maintenance costs include fuel (except nuclear), and non-fuel costs. Fuel costs have been responsible for a large portion of recent rate increases at the national level. Depending upon the mix of fuels used in each region, fuels are also a major element of operating costs, by region. In order to reflect the relative differences by fuel type, the fuel cost component at the regional level is based on the relationship of regional fuel prices to the average national price for each fuel. Exhibits II-17 through II-19 present the fuel price index by region for 1975, 1980, and 1985. New England and the Middle Atlantic generally show the highest prices for all fuel types.

The non-fuel costs component is also based on the relationship between non-fuel operating and maintenance costs by region to the national average. Again, New England and the Middle Atlantic are experiencing the highest costs among the regions, as is illustrated in Exhibits II-17 through II-19.

Financial Structure

The logic which represents the financial structure of the electric utility industry at the national level is replicated in the regional projections. Only the data which designates the share by ownership type (public or private) as a percent of capacity is unique to each region. Exhibits V-17 through V-19 illustrate that in four of ten regions, New England, Middle Atlantic, East North Central, and South Atlantic, the public ownership share is less than 10 percent. In five of the remaining six regions the public share ranges from 18 to 61 percent. Among the investor-owned firms, the percentage breakdown between those using normalized and those using flow-through accounting is also apportioned in a manner unique to each region. Exhibits V-17 through V-19 provide the assumptions used in this category.

FINANCIAL PROJECTIONS[3]

The financial profile which is implied by the regional projections of the utility industry's operations is described by the same indicators as are used at the national level:

- Capital Expenditures
- External Financing
- Operating & Maintenance Costs
- Operating Revenues
- Average Consumer Charges

Capital Expenditures are the expenditures for plant and equipment placed in service during any given year. These expenditures are primarily the result of the additions to capacity made in response to the projected level of sales and peak demand. The table below summarizes the level of capital expenditures by region in the short-run (1975-1980) and over the 1975-1985 decade. The table also illustates the differences among regions of the average capital expenditure cost per kilowatt, which reflects the mix of fuels used in each region.

---

[3] *Financial information was not available for Alaska and Hawaii.*

CAPITAL EXPENDITURES FOR GENERATION*
AS REFLECTED IN CAPACITY ADDITIONS
(1975 dollars)

	Capital Exp.** 1975-1980 (billions)	Avg. Cost/kw 1975-1980*	Capital Exp. 1975-1985 (billions)	Avg. Cost/kw 1975-1985*
New England	$ 4.13	$526	$ 9.30	$577
Middle Atlantic	11.32	497	24.16	577
East North Central	18.48	402	35.35	467
West North Central	8.47	308	15.64	355
South Atlantic	21.43	466	51.24	522
East South Central	15.18	473	21.80	523
West South Central	16.58	311	40.15	378
Mountain	10.23	363	16.73	398
Pacific	12.22	440	22.48	486
Alaska & Hawaii	n.a.	n.a.	n.a.	n.a.
National***	$118.27	$413	$237.13	$472

**This measure excludes $235/kw standard cost for transmission and distribution plant and equipment*

***Capital expenditures are net of the change in CWIP*

****From national baseline - Alaska and Hawaii account for differences in total dollars.*

Source: PIm (Electric Utilities)

By the end of the 1975-1985 decade the average cost per kilowatt ranges from $355 to $577. The four regions with the highest cost per kilowatt, New England, Middle Atlantic, South Atlantic and East South Central, plan to add nuclear capacity of 40 to 60 percent of capacity additions through 1985 (see Exhibit V-8). During the same period, the West South Central region will no longer maintain the lowest cost per kilowatt because of a shift from gas (the least expensive fossil fuel) to coal and nuclear power, since gas additions are projected to cease after 1977. West North Central, which does maintain the lowest average cost per kilowatt, is one of the slower growing regions and will meet a large part of its future demand with the addition of peaking units.

Despite the range in average costs among regions, the total capital expenditures are primarily a direct function of the level of additions. Capital expenditures, in fact, are highest in the South Atlantic, East North Central, and West South Central regions where capacity additions are also greatest. Those three regions account for 48 percent of the total capital expenditures in the 1975-1990 period and 54 percent in the 1975-1985 decade. They also account for over 50 percent of the projected additions by 1985. Overall, there is a wide range of capital expenditure levels among regions, ranging from $9 billion to $51 billion for 1975-1985.

External Financing. The level and timing of capital expenditures and the attendant requirements for external financing are of major concern to the electric utilities. External financing requirements are primarily a function of the level of capital expenditures and will range from a low of $6.7 billion in the next ten years in New England, to a high of $39.1 billion in South Atlantic. The table below presents these requirements by region for the short-term and the period through 1985. The remaining funds required to finance capital expansion will be generated internally from retained earnings, depreciation, and tax deferrals.

EXTERNAL FINANCING
DURING 1975-1980 and 1975-1985
(billions 1975 dollars)

	1975-1980	1975-1985
New England	$ 2.77	$ 6.74
Middle Atlantic	5.12	14.95
East North Central	11.42	23.40
West North Central	5.00	10.28
South Atlantic	12.51	39.09
East South Central	8.96	13.17
West South Central	16.38	37.81
Mountain	7.39	12.37
Pacific	7.58	15.48
Alaska & Hawaii	n.a.	n.a.
National**	$89.84	$191.23

The 1975-1980 period reflects modified FPC announced capacity additions

***PTm National Baseline Projections*

Source: Exhibit V 8-10, PTm Electric Utilities

Operating Costs and Revenues. Operating and maintenance costs consist of all direct costs of operation; operating revenues must cover these operating costs as well as taxes and cost of capital. The operating costs are a significant component of rates, which are in turn, the most visible and politically volatile aspect of electricity production and consumption. The operating costs are also a measure of fuel costs (except nuclear), generation, operating conditions and utilization patterns.

In 1974, the variations of operating costs among regions on a kilowatt-hour basis began to be driven increasingly by the types of fuel used to generate electricity. The rise in all fuel costs since 1974, and the uncertainties of supply have caused fuel costs to play a dominant role in determining levels of operating and maintenance costs. The table below illustrates the differences in the projected annual costs for operating and maintenance and the distribution of these costs on a per kilowatt hour basis.

OPERATION AND MAINTENANCE COSTS
(1975 dollars)

	1980*	Mills/kwh 1980	1985*	Mills/kwh 1985
New England	$ 2.38	23.0	$ 2.69	20.1
Middle Atlantic	7.45	23.5	8.63	22.2
East North Central	7.75	17.0	10.03	17.9
West North Central	2.32	15.8	3.28	17.5
South Atlantic	8.42	17.1	11.19	16.3
East South Central	2.57	12.4	3.11	12.9
West South Central	4.49	12.3	5.63	10.7
Mountain	1.40	11.0	2.04	12.5
Pacific	4.65	13.6	5.39	12.8
Alaska & Hawaii	n.a.	n.a.	n.a.	n.a.
National**	42.76	16.7	53.75	16.2

---

*billions of dollars

**from national baseline runs

Source: PTm (Electric Utilities)

The total cost reflects the number of kilowatt hours generated, the cost per kilowatt hour illustrates more directly the effect of fuel costs.

New England and the Middle Atlantic, which are heavy oil users, may sustain even higher fuel costs than are currently projected. Those regions with substantial usage of hydroelectric power -- East South Central, Mountain, and Pacific have a lower cost per kilowatt-hour, although not the lowest annual costs for operating and maintenance since these costs are a direct result of the total number of kilowatt hours generated. The projected increase in gas prices and greater usage of coal will cause an increase in cost per kilowatt-hour in West South Central.

The revenues which are required to cover these costs are most clearly reflected in consumer charges (discussed in the following section). Exhibit 2 in the appendix for each region indicates that the South Atlantic region is projected consistently to have the highest level of operating revenues. The amount of revenues is determined by the number of customers, the growth in the usage per customer, and finally, the level of consumer charges. The South Atlantic is among the highest region on all of these measures.

Average Consumer Charges are obtained from dividing operating revenues by total sales to ultimate customers.[4] Thus, they represent the average cost of electrical energy per kilowatt-hour sold. The table below presents consumer charges by region for selected years.

CONSUMER CHARGES BY REGION
FOR SELECTED YEARS
(mills/kwh)

	1974*	1974**	1980	1985
New England	36.4	39.9	40.5	39.0
Middle Atlantic	34.4	37.7	38.7	38.2
East North Central	22.6	24.7	32.1	33.3
West North Central	22.8	25.0	34.3	35.7
South Atlantic	24.1	26.4	36.7	37.4
East South Central	14.9	16.3	27.5	25.4
West South Central	18.2	19.9	26.9	28.6
Mountain	18.5	20.3	36.4	36.3
Pacific	18.4	20.1	21.1	20.2
Alaska & Hawaii	29.4	32.2	n.a.	n.a.
National**	23.0	25.2	31.7	32.0

**Actual EEI Statistical Yearbook 1974*

***Adjusted to 1975 dollars*

****1975-1985 PTm national baseline*

Source: PTm (Electric Utilies)

---

[4] *Includes all customer classes*

The consumer charges in the table do not manifest the same range in mills per kilowatt-hour as do operation and maintenance costs; the difference is primarily accounted for by differences in capital costs. However, the New England and Middle Atlantic regions consistently maintain the highest charges to customers. Most regions cluster closely around the national average; only the Pacific region attains noticeably lower charges in 1985 than the national average, or than the other regions. The West South Central region's consumer charges, in line with the aforementioned increases in gas costs and the change in generation mix, are projected to be just 10 percent lower than the national average in 1985, as compared to 26 percent lower in 1975.

The projections presented in this chapter provide a basis for the comparison of the financial conditions which are likely to exist as a result of compliance with pollution control regulations. The following chapter discusses the result of that comparison for each region.

CHAPTER 3

REGIONAL POLLUTION CONTROL IMPACTS

The financial impact analysis of the pollution control regulations is presented from two perspectives: first, on a comparative basis for all regions using consumer charges as a measure of impact, the second on a non-comparative basis which focuses on the change in capital expenditures, external financing, and operating and maintenance costs within each region. The region by region discussion also relates the levels of expenditures and costs to the characteristics of generating capacity and the amount of capacity affected by the regulations in each region. The impacts become readily apparent when the costs associated with pollution control are compared to the baseline financial projections. On the other hand, discussion of the results for each of the nine regions can be cumbersome and repetitive. As a result, the material included in this chapter covers the most essential elements common to all regions. Additional detail can be found in the appendices and exhibits at the end of the volume.

METHODOLOGY

As for the national impact analysis presented in Volume III, the methodology for the regional analysis has required developing industry projections for 1975-1990 which include the costs of complying with federal pollution control regulations. The pollution control impacts then have been determined by comparing those projections to the baseline projections above which exclude federal pollution control costs.

This analysis includes three important inputs with respect to pollution control costs and compliance stragegies:[1]

Pollution Control Equipment Costs

Capital and annual costs used in the regional analysis for pollution control equipment were the same as those described in Chapter 3 of Volume III. It was assumed that the effect of site-specific factors would outweigh any variation in regional construction costs and, therefore, the plant unit costs used for each region were identical.

Capacity Affected by Air Regulations

TBS determined the amounts of coal capacity affected by the air regulations by using estimates developed for EPA by Sobotka and Co., Inc. Sobotka employed a coal supply and demand balance model to assign least-cost strategies for burning coal in an environmentally acceptable manner (meeting SIP's or NSPS[2]) to each plant in the country. Regional aggregations of these strategies were then provided to EPA along with the incremental cost of complying coal. Particulate compliance status was provided by PEDCO-Environmental. Detailed exhibits in Appendices A through I document the control strategies used in each region by 1985.

Capacity Affected by Water Regulations

The estimates which TBS used to designate capacity affected by the thermal, chemical and entrainment regulations were developed by the national and regional offices of EPA. EPA surveyed the water permit officers in each EPA regional office to obtain estimates of the megawatts of capacity (nuclear and fossil) affected by the final thermal effluent guidelines (both before and after Sec. 316(a) determinations), the chemical guidelines, the entrainment regulations (Sec. 316(b) of the Federal Water Pollution Control Act), and the various State Water Quality Standards (SWQS). Appendices A through I also include the results of this survey.

---

[1] *Volume III discusses the history and intent of the regulations and covers all terminology and major issues associated with compliance.*

[2] *State Implementation Plans (SIP)*
New Source Performance Standards (NSPS)

IMPACT OF POLLUTION CONTROL COMPLIANCE AS MEASURED BY CONSUMER CHARGES

Consumer charges represent the average cost of electrical energy per kilowatt hour.[3] Consumer charges bring into one number the relationship between the operating, capital and other costs, and the sales to ultimate customers. They are also stated on a per unit basis. As such, consumer charges are a consistent measure for comparison among regions of the potential impact of pollution control regulations which require capital investments as well as direct operating costs.

Nationally, the average impact on consumer charges is 6.7 percent by 1985. By region, this impact varies from as low as 1.3 percent to 11.1 percent. The largest impact will take place in the Mountain and West North Central regions, where the increased cost will be about 4 mills (1975 dollars) per kwh, or 10 to 11 percent. These two regions will add significant coal capacity during 1975 to 1985 and are among the smallest regions in capacity and generation (see Exhibits V-12 and V-13). For this reason, the high absolute costs are spread over a small base and, therefore, have a large impact.

---

[3] *Kilowatt-hours will be abbreviated as kwh in the remaining sections of this chapter.*

The three regions, East South Central, East North Central, and West South Central, will experience a moderately high impact of 2.6 to 2.8 mills per kwh or 8 to 10 percent. During the decade, all three regions will add large amounts of both coal and nuclear capacity. In the East South Central and East North Central regions, coal and nuclear additions will be added to an already large volume of coal capacity, while in the West South Central area, the mix of additions will shift the generation away from usage of natural gas.

A moderate impact of 4 to 5 percent, slightly below the national average, is expected in the South and Middle Atlantic regions. The absolute change will be 1.6 to 1.9 mills per kwh for meeting both air and water pollution control regulations.

The remaining two regions, New England and Pacific, have very limited coal capacity and plan little or no new coal units. In both of these regions, the impact for compliance with pollution control regulations will be less than 2 percent, or under one mill per kilowatt-hour.

The following table indicates the impact on consumer charges of current air and water regulations across regions. The four levels of impact--high, moderately high, moderate and low--are shown as separate categories on the table.

IMPACT OF CURRENT LEGISLATION
AIR AND WATER REGULATIONS ON
CONSUMER CHARGES
1985
(1975 dollars)

	Consumer Charges Including Impacts	Increase from Baseline	
	mills/kwh	mills/kwh	%
High			
Mountain	40.3	4.0	11.1
West North Central	39.3	3.6	10.1
Moderately High			
East North Central	36.0	2.8	8.3
East South Central	28.0	2.6	10.2
West South Central	31.2	2.6	9.0
Moderate			
South Atlantic	39.4	1.9	5.2
Middle Atlantic	39.8	1.6	4.1
Low			
New England	39.7	0.7	1.8
Pacific	30.5	0.3	1.3

Source: Exhibits 2 and 5, Appendices V A-I.

IMPACTS PROJECTED REGION BY REGION

The financial impacts which are projected to result from compliance with pollution control regulations are described below for each region. The impacts on capital expenditures, external financing and operating and maintenance expenses are highlighted. These financial indicators will be related to two factors: the physical growth and the capacity mix by fuel type in each region. The regions which will experience the largest impact will be those which add substantial coal and nuclear capacity.

Air regulations affect fewer units, primarily those burning coal, than the water regulations; however, the control strategies required to meet the air regulations are far more costly than those required to meet the water regulations. There is a direct correlation between the coal capacity in each region by 1985 and the absolute costs incurred in the same period to comply with federal regulations.

The two pollution control strategies which are projected to be used most heavily for achieving compliance with the regulations are scrubbers and cooling towers.[4] The installation of scrubbers is the major expense related to control of sulfur dioxide; cooling towers will be used at coal and nuclear plants for compliance with the water regulations (thermal and entrainment control). Plants installing cooling towers would have used once-through cooling without the regulations.

---

[4] *Given current available technology.*

New England (Region I)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$9.3
Impact	+ 0.3
% Change from Baseline	3.6%
External Financing Since 1974	
Baseline	$6.7
Impact	+ 0.4
% Change from Baseline	5.5%
Operating and Maintenance Expense	
Baseline	$2.7
Impact	*
% Change from Baseline	1.1%

---

[1] *Net of CWIP*
**Less than .05*
Source: Exhibits V-A-2 and V-A-5

New England will experience a small impact in meeting pollution control regulations. In the 1975-1985 period, this region will incur about $350 million in capital expenditures, all of which will be met by external financing. Operating and maintenance expenses will be less than $50 million in 1985. No coal additions are expected; most of the growth will consist of 6.6 million kilowatts of added nuclear capacity. By 1985, nuclear units will comprise 40 percent of the 28.8 million kilowatts of total capacity.

Of the total impact, very little is the result of compliance with air regulations. About $3 million or one percent of the total is in this category. Ninety-nine percent of the costs for both nuclear and fossil compliance are associated with thermal, chemical and entrainment guidelines.

Capital expenditures for compliance with federal water regulations account for $346 million ($325 million for cooling towers). In addition, the stringent State Water Quality Standards (SWQS) are responsible for an increase of 26 percent of the requirements for fossil cooling towers. SWQSs account for $86 million more in total capital expenditures. For operating and maintenance expenses, federal compliance results in $33 million ($32 million caused by cooling tower operation and maintenance); the state standards are responsible for another $9 million.

Middle Atlantic (Region II)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$24.2
Impact	+ 2.5
% Change from Baseline	10.2%
External Financing Since 1974	
Baseline	$15.0
Impact	+ 2.1
% Change from Baseline	14.0%
Operating and Maintenance Expense	
Baseline	$ 8.6
Impact	+ 0.3
% Change from Baseline	3.4%

---

[1] *Net of CWIP*

Source: Exhibits V-B-2 and V-B-5

Electricity consumption in the Middle Atlantic region is expected to grow at a much slower rate than the national average over the next ten years. The majority of its capacity additions will be nuclear units which will be affected by the water guidelines. Coal units equal to 25.8 million kilowatts in 1985 will be brought into compliance primarily by the use of precipitators and scrubbers.

In total, Middle Atlantic will incur about $2.5 billion in capital costs for pollution control strategies, an impact of 10 percent on baseline projections. The capital expenditure requirements for the 1975-1985 decade include $1.4 billion for compliance with the water regulations by fossil and nuclear units. Scrubbers account for another $500 million of the total.

Despite the 10 percent impact on capital expenditures, the reliance on a combination of precipitators and scrubbers and the use of some Western low sulfur coal and blending, is expected to keep additional operating and maintenance expenses to $300 million dollars, or an impact of about 3 percent.

State Water Quality Standards will require approximately $400 million more in capital expenditures during this period and account for almost $40 million per year in operating and maintenance expenses.

East North Central (Region III)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$35.3
Impact	+ 5.0
% Change from Baseline	14.3%
External Financing Since 1974	
Baseline	$23.4
Impact	+ 4.4
% Change from Baseline	18.8%
Operating and Maintenance Expense	
Baseline	$10.0
Impact	+ 0.7
% Change from Baseline	6.7%

---

[1] *Net of CWIP*

Source: Exhibits V-C-2 and V-C-5

In 1974, East North Central was the region with both the largest total capacity and largest coal capacity. As a result of a moderate growth rate during the next eleven years, this region will have a capacity of 125.9 million kilowatts in 1985 which will place it behind the South Atlantic region in size by the end of the decade. In that period, East North Central will continue to add coal-fired units and in 1985 will have 89 million kilowatts--the most coal-fired units in any region. With this high level of coal capacity, East North Central can expect an extremely high capital expenditure requirement for pollution control equipment. Only 10 million kilowatts (11 percent of the coal-fired units) were estimated to be in compliance with air regulations in 1974; coal units of 79.5 million kilowatts will require pollution control equipment. The air regulation strategies account for 98 percent of all pollution control costs.

This region has a minimal requirement for compliance with the effluent guidelines. Only 2.3 million kilowatts are expected to require cooling towers and all the fossil and nuclear capacity are expected to be exempt from the entrainment and chemical guidelines.

Despite the minimal water regulation requirements and associated costs, East North Central will incur higher capital and operating costs in absolute dollars than any other region. Scrubbers are expected to be used as the control strategy for 34 million kilowatts, and this alone will require a capital cost of over $3 billion. The total capital expenditures during 1975-1985 will be about $5 billion, a 14 percent increase over the baseline projections. Almost all of these monies must be financed externally, causing an increase of about 19 percent in external financing.

Pollution control strategies will require an additional $675 million for operating and maintenance expenses in 1985. Although the impact is the largest of any region in absolute dollars, it adds less than 7 percent to the baseline projection for this region because of its high level of baseline expenditures.

West North Central (Region IV)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$15.6
Impact	+ 2.8
% Change from Baseline	17.6%
External Financing Since 1974	
Baseline	$10.3
Impact	+ 2.3
% Change from Baseline	22.4%
Operating and Maintenance Expense	
Baseline	$ 3.3
Impact	+ 0.3
% Change from Baseline	8.2%

---

[1] *Net of CWIP*

Source: Exhibits V-D-2 and V-D-5

West North Central will experience a high impact in meeting pollution control regulations. In terms of installed capacity it was the third smallest region in the United States in 1974 and its growth in the next decade will follow the national average.

West North Central will be highly reliant on fossil-fired steam generation throughout the decade. In 1974, coal and gas units accounted for 70 percent of the capacity. Conversions of gas units to coal and the addition of new coal units will increase the coal capacity to 36 million kilowatts by 1985 or 67 percent of the total capacity. The air regulations will affect almost all of the coal-fired units. The water regulations will affect 21 million kilowatts of the coal units and 1.6 million kilowatts of the nuclear units.

West North Central will incur a total of $2.8 billion in capital expenditures for new and retrofit pollution control equipment, 82 percent of which will be financed externally. Additional operating expenses will amount to about $270 million in 1985. Scrubbers and cooling towers will account for $1.8 billion in capital equipment and $140 million in operating and maintenance expense.

In absolute dollars, this level of total costs is the average for all regions. As stated above, West North Central is one of the smallest regions and is expecting only a moderate growth. In light of this, the baseline projection for capital expenditures is low and the percentage impact of compliance with pollution control regulations is the highest of all regions. Capital expenditures will be almost 18 percent higher and external financing will be 22 percent higher than the baseline.

With gas conversions to coal, West North Central will incur higher baseline operating and maintenance costs in 1985 than in 1974. Therefore, the additional pollution control operating costs are related to an already higher baseline and result in a more moderate percentage impact than is manifested in capital costs. The $270 million incurred for pollution control operating and maintenance expenses will be an 8.2 percent increase in 1985.

South Atlantic (Region V)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$51.2
Impact	+ 4.5
% Change from Baseline	8.7%
External Financing Since 1974	
Baseline	$39.1
Impact	+ 4.3
% Change from Baseline	11.0%
Operating and Maintenance Expense	
Baseline	$11.2
Impact	+ 0.7
% Change from Baseline	5.9%

---

[1] *Net of CWIP*

Source: Exhibits V-E-2 and V-E-5

South Atlantic was the second largest region in 1974 with 83 million kilowatts of installed capacity. The period 1975-1985 will exhibit a 70 percent growth, well above the national average. Thus , in 1985, South Atlantic is projected to have the largest amount of installed capacity--141 million kilowatts or about 10 percent higher than East North Central.

Historically, this region has relied heavily on coal and oil for its generation. The Arab oil embargo and the high cost of oil have resulted in conversions to coal of many oil-fired units. The capacity additions in the decade 1975-1985 will be predominantly coal and nuclear units, 24.3 million kilowatts and 27.9 million kilowatts respectively. The coal share will continue to be about 50 percent of the capacity in 1985 and the nuclear units will account for another 24 percent in that year.

The air regulations are expected to affect 48.2 million kilowatts of coal-fired units. The thermal and entrainment guidelines are estimated to require cooling towers on 26.2 million kilowatts of coal-fired units and 26.9 million kilowatts of nuclear units. All of the coal capacity, 67.5 million kilowatts, and about one-half of the nuclear capacity, 16.4 million kilowatts, is expected to be impacted by the chemical effluent guidelines.

The large amount of coal capacity in South Atlantic and the large percentage of units required to meet both air and water regulations will result in a high level of capital and operating costs for new and retrofit pollution control equipment. The region will incur almost $4.5 billion in capital expenditures; $4.3 billion will be financed externally. An additional $650 million will be required for operating and maintenance expenses in 1985. Scrubbers and cooling towers alone will account for $3.4 billion of capital costs (76 percent of the total) and $440 million in operating costs (67 percent of the total).

In light of the high growth expected during this period, the baseline capital and operating costs are the highest of all regions. Therefore, the impact of pollution control in the South Atlantic region, while high in absolute terms, appears more moderate in relative terms. The $4.5 billion of capital expenditures will result in an 8.7 percent increase and the $650 million in operating expenses will cause only a 6 percent increase over the baseline projections.

East South Central (Region VI)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$21.5
Impact	+ 3.4
% Change from Baseline	15.6%
External Financing Since 1974	
Baseline	$13.2
Impact	+ 2.6
% Change from Baseline	19.7%
Operating and Maintenance Expense	
Baseline	$ 3.1
Impact	+ 0.3
% Change from Baseline	8.7%

---

[1] *Net of CWIP*

Source: Exhibits V-F-2 and V-F-5

East South Central is unique with respect to the predominance of publicly-owned utilities. The high proportion of publicly-owned systems is due primarily to the presence of the Tennessee Valley Authority. The region is also heavily reliant upon coal-fired capacity; 71 percent of its total capacity in 1974 was coal. The share of coal capacity and the uniquely large public share of system ownership are two important factors in the types of impact which are expected in the region.

During the period 1975-1985 the private sector will continue to add coal units; TVA will add the nuclear capacity. In 1985, the capacity mix will include 36.8 million kilowatts of coal-fired units (57 percent) and 13.9 million kilowatts of nuclear units (22 percent). The federal regulations on air and water pollution will, therefore, affect most of the capacity in East South Central.

Almost all the 36.8 million kilowatts of coal plants is expected to be affected by the air regulations. Scrubbers are projected on 13.8 million kilowatts while a combination of precipitators, low and medium sulfur coal, and blending is expected on 22 million kilowatts. In addition, all fossil units are expected to be affected by the chemical effluent guidelines. Cooling towers are projected for 16.8 million kilowatts of fossil capacity in order to meet the federal thermal effluent guidelines and for an additional 7.3 million kilowatts in order to meet the more stringent State Water Quality Standards. All nuclear plants are expected to require cooling towers when the units are put in-service, while 95 percent are projected to be impacted by the chemical guidelines.

As a result, the capital expenditures required for new and retrofit pollution control equipment in this region are above the average level. East South Central will incur $3.4 billion in capital costs, which is an increase of 15.6 percent on the baseline. More than three-fourths of these expenditures are for scrubbers and cooling towers. East South Central will need to meet 75 percent of its capital costs with external financing. This is a smaller percentage than in any other region and yet the increase over the baseline level of external financing is almost 20 percent.

The use of the full spectrum of control alternatives will keep the operating and maintenance expenses at $270 million, or 8.7 percent over the baseline level in 1985. Compliance with the air regulations will account for over $200 million while the water will account for another $65 million.

West South Central (Region VII)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$40.1
Impact	+ 3.4
% Change from Baseline	8.5%
External Financing Since 1974	
Baseline	$37.8
Impact	+ 3.4
% Change from Baseline	9.0%
Operating and Maintenance Expense	
Baseline	$ 5.6
Impact	+ 0.6
% Change from Baseline	10.6%

---

[1] *Net of CWIP*

Source: Exhibits V-G-2 and V-G-5

West South Central is expected to almost double in capacity during 1975 to 1985, from 64 to 114 million kilowatts. Its coal capacity will increase from 7 to 36 percent of total capacity as a result of new units and gas conversions.

Only 1.2 million kilowatts of coal-fired units were in compliance with air regulations in 1974. All other units and the new units are expected to require some change in order to comply with the air regulations. These coal units are also expected to be affected by the water regulations. By 1985 the West South Central region will also add 13 million kilowatts of nuclear capacity. All these units are expected to be exempt from thermal and 316(b) guidelines and only 10 percent are expected to be affected by the chemical guidelines. The costs of pollution control in the West South Central region, therefore, are in direct correlation with the level of coal capacity. The region can expect a moderately high percentage impact in meeting the federal air and water regulations. While this region will add the largest amount of coal capacity of any region, it is expected to use mainly Western low sulfur coal to comply with the air regulations. The capital cost of this strategy is considerably lower than that of using scrubbers and will help to moderate the level of costs for pollution control.

West South Central is projected to incur a total of $3.4 billion in capital expenditures for the period 1975-1985, or an impact of 8.5 percent. The major share of these costs will be associated with Western low sulfur coal. This strategy is expected to be used for 28.8 million kilowatts, or 69 percent of the coal capacity, and will require $2.2 billion in capital costs (65 percent of the total impact). Scrubbers are projected to account for most of the additional costs. Only 4 percent of the impact is a result of the water regulations.

Additional operating and maintenance expenses for pollution control in 1985 will be almost $600 million and $443 million of this total is associated with Western low sulfur coal (74 percent) and $125 million is for scrubbers. The additional operating costs will affect the baseline by 10.6 percent.

Mountain Region (Region VIII)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$16.7
Impact	+ 2.5
% Change from Baseline	15.2%
External Financing Since 1974	
Baseline	$12.4
Impact	+ 2.0
% Change from Baseline	16.1%
Operating and Maintenance Expense	
Baseline	$ 2.0
Impact	+ 0.2
% Change from Baseline	10.8%

---

[1] *Net of CWIP*

Source: Exhibits V-H-2 and V-H-5

The Mountain region will experinece a high percentage impact in meeting pollution control regulations. Although the region will almost double in capacity in 1985, from 24 to 47 million kilowatts, it will still remain the second smallest in total capacity. Most of the new capacity, about 72 percent, will be coal-fired units which are expected to require scrubbers.

The impact of compliance will be significant because of the relatively low level of baseline capital expenditures anticipated before considering pollution control expenses. The projected pollution control expenditures of $2.5 billion in capital expenditures during 1975-1985 and $222 million in operating and maintenance expenses in 1985 represent increases of 15.2 and 10.8 percent above baseline levels, respectively. Air regulations are expected to account for 97 percent of these expenditures. Scrubbers alone are projected to cost $2 billion in capital expenditure and $173 billion in 1985 operating costs. The region is expected to meet 80 percent of its capital needs with external financing.

Pacific (Region IX)

IMPACTS OF AIR AND WATER REGULATIONS TO 1985
(billion 1975 dollars)

	1985
Capital Expenditures[1] Since 1974	
Baseline	$22.5
Impact	+ 0.6
% Change from Baseline	2.4%
External Financing Since 1974	
Baseline	$15.5
Impact	+ 0.5
% Change from Baseline	3.2%
Operating and Maintenance Expense	
Baseline	$ 5.4
Impact	+ 0.1
% Change from Baseline	1.1%

---

[1] *Net of CWIP*

Source: Exhibits V-I-2 and V-I-5

In 1974, hydroelectric power represented about 50 percent of the 58 million kilowatts of installed capacity in the Pacific region. Gas and oil accounted for another 40 percent. By 1985, however, the shares by fuel type will have changed in spite of continued additions of hydroelectric power. Gas units will have been converted to oil, and 10 million kilowatts of nuclear capacity and 5 million kilowatts of coal will have been added. Consequently, the region will be affected to some degree by the air and water regulations, although the impact will be the smallest of all the regions.

The low level of coal capacity is projected to require capital expenditures of less than $300 million for scrubbers and Western low sulfur coal, $255 million for cooling towers and less than $1 million to meet the chemical guidelines. Only 1.6 million kilowatts, or 13 percent, of the nuclear capacity, is expected to require cooling towers, and the total nuclear capacity is expected to be exempt from the entrainment, 316(b), and chemical guidelines.

Total projected capital expenditures of $550 million for pollution control would result in an increase above the baseline of only 2.4 percent. The pollution control strategies would add $58 million in 1985 operating and maintenance expenses, or 1 percent of the baseline amount.

SUMMARY OF CAPITAL EXPENDITURES AND OPERATING & MAINTENANCE EXPENSES

In summation, the impacts discussed in the regional subsections above are assembled in one table as an overview of all the regions. The table emphasizes the variability of the impacts as they are expected to be experienced across regions.

IMPACTS OF CURRENT LEGISLATION
AIR AND WATER REGULATIONS
1975-1985

(billions of 1975 dollars)

	CUMULATIVE CAPITAL EXPENDITURES* 1975-1985			OPERATING & MAINTENANCE EXPENSES 1985		
		Change**			Change**	
	Baseline	$	%	Baseline	$	%
New England	9.3	0.3	3.7	2.7	***	1.1
Middle Atlantic	24.2	2.5	10.2	8.6	0.3	3.4
East North Central	35.3	5.0	14.3	10.0	0.7	6.7
West North Central	15.6	2.8	17.6	3.3	0.3	8.2
South Atlantic	51.2	4.5	8.7	11.2	0.7	5.9
East South Central	21.5	3.4	15.6	3.1	0.3	8.7
West South Central	40.1	3.4	8.5	5.6	0.6	10.6
Mountain	16.7	2.5	15.2	2.0	0.2	10.8
Pacific	22.5	0.6	2.4	5.4	0.1	1.1
National Percent Change		10.5%			5.0%	

Net of change in CWIP

***Change from baseline projections, See Appendix A-I, Exhibit 5.*

****Less than .05*

Exhibit V-1

ESTIMATED INSTALLED GENERATING CAPACITY
1972 BASELINE YEAR

(kilowatts in thousands - name plate)

Generator Drive Type	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii	Generator Type Totals
Conventional Hydro											
Capacity	1,449	4,166	840	2,681	4,956	5,259	2,009	6,294	24,191	79	51,924
PORC*	9.0	7.0	1.1	9.6	7.3	14.8	4.0	31.5	48.9	5.6	
Pumped Storage											
Capacity	31	1,801	-	408	549	-	271	307	1,275	-	4,642
PORC*	0.3	3.0	-	1.5	0.8	-	0.5	1.5	2.6	-	
Nuclear Steam											
Capacity	3,469	2,140	5,486	569	2,376	-	-	-	1,310	-	15,300
PORC*	20.5	5.0	8.0	2.0	3.5	-	-	-	2.5	-	
Peaking Units											
Capacity	1,379	9,255	4,994	3,322	5,976	1,347	1,240	712	626	173	29,024
PORC*	8.6	15.6	6.6	11.9	8.8	3.8	2.5	3.6	1.4	12.4	
Coal											
Capacity	561	20,582	56,790	12,869	33,517	25,670	1,207	5,897	-	172**	157,265
PORC*	3.4	35.2	77.1	46.1	49.6	72.2	2.4	29.5	-	12.3	
Oil											
Capacity	9,355	18,345	2,425	545	16,061	492	1,162	530	6,604	575**	56,094
PORC*	57.4	31.2	3.1	2.0	23.8	1.4	2.3	2.7	13.4	41.0	
Gas											
Capacity	111	1,742	2,987	7,513	4,137	2,779	44,045	6,230	15,402	403**	85,357
PORC*	0.8	3.0	4.1	26.9	6.2	7.8	88.3	31.2	31.2	28.7	
	16,355	58,039	73,472	27,907	67,572	35,547	49,934	19,970	49,408	1,402	399,606

**PORC - Percentage of Regional Capacity*

***Alaska & Hawaii Fossil Capacity Estimated at 15 percent coal, 50 percent oil, and 35 percent natural gas.*

Preceding page blank

Source: EEI Statistical Yearbook, 1972 and 1973; Federal Power Commission, Statistics for Privately-Owned Utilities, 1972, and Hydro Electric Plant Construction Cost and Annual Production Expenses, 1969 and 1970; and National Coal Association, Steam Electric Plant Factors, 1973 and 1974

Exhibit V-2

REGIONAL HISTORICAL FOSSIL TRENDS*
PERCENT OF GENERATION

(for selected years)

Year	United States			New England			Middle Atlantic			East North Central			West North Central			South Atlantic			East South Central			West South Central			Mountain			Pacific		
	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas	Coal	Oil	Gas
1960	66	8	26	58	37	5	78	14	8	96	-	4	47	1	52	77	8	15	92	-	8	-	-	100	26	8	66	-	32	68
1963	65	7	28	63	33	4	75	15	10	96	-	4	49	1	50	79	10	11	92	-	8	-	-	100	40	4	56	-	19	81
1966	66	8	26	61	36	3	77	16	7	97	-	3	51	1	48	80	12	8	92	-	8	-	-	100	49	4	47	-	19	81
1969	59	12	29	25	74	1	60	32	8	94	-	6	54	1	45	73	15	12	89	-	11	-	-	100	51	3	46	-	17	83
1972	54	19	27	6	93	1	52	44	4	91	4	5	62	2	36	62	29	9	89	2	9	1	2	97	58	4	38	-	30	70
1973	57	20	23	5	94	1	56	41	3	93	4	3	65	2	33	63	30	7	93	2	5	3	6	91	64	7	29	6	46	48
1974**	57	20	23	10	87	3	54	43	3	90	6	4	66	3	31	63	30	7	93	3	5	3	6	91	67	8	25	6	54	40

*No information available for Alaska and Hawaii

**EEI Statistical Yearbook 1974

Source: National Coal Association, Steam Electric Plant Factors, 1960-1974

Exhibit V-3

ULTIMATE CUSTOMER KWH USAGE AND GROWTH RATES

1960 - 1974

	United States	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
						kWh Usage/Customer					
1960	11,605	7,326	9,426	12,370	8,381	10,770	23,625	10,348	13,598	13,428	9,766
1961	11,986	7,770	9,843	12,606	8,619	11,303	13,537	10,639	14,608	13,939	10,463
1962	12,656	8,212	10,325	13,319	9,394	12,121	23,943	11,876	15,205	14,327	11,079
1963	13,218	8,501	10,794	13,886	9,767	12,631	24,789	12,843	15,483	14,846	11,577
1964	13,330	8,913	11,405	14,435	10,273	13,386	25,425	13,704	16,254	15,687	12,022
1965	14,543	9,491	12,081	14,987	10,791	14,241	25,762	14,747	16,671	16,329	12,526
1966	15,528	10,127	12,821	15,763	11,464	15,433	26,665	16,056	17,953	17,768	13,261
1967	16,240	10,740	13,307	16,434	12,278	16,263	26,791	17,261	18,346	18,627	13,929
1968	17,246	11,513	14,131	17,467	13,096	17,580	27,749	18,644	19,179	19,428	14,549
1969	18,429	12,275	15,126	18,443	14,078	18,845	28,815	20,901	20,738	20,533	15,555
1970	19,195	12,926	15,795	18,921	14,863	20,027	29,589	22,205	21,133	21,030	16.239
1971	19,746	13,571	16,223	19,562	15,258	20,703	29,859	22,916	21,201	21,501	17,479
1972	20.718	14,351	16,913	20,712	15,920	21,488	31,418	24.760	21,737	22,170	18,246
1973	21,708	15,051	17,810	22,086	16,845	22,729	32,987	25,804	22,039	22,219	19,165
1974	21,232	14,582	17,228	21,550	16,678	21,942	34,168	25,913	22,397	21,470	19,396
					Usage/Customer Change						
						(percent)					
1960-1961	3.3	6.1	4.4	1.9	2.9	4.9	0.4	2.8	7.9	3.8	7.1
1961-1962	5.6	5.7	4.9	5.7	9.0	7.2	1.7	11.6	3.7	2.8	5.9
1962-1963	4.4	3.5	4.5	4.3	4.0	4.2	3.5	8.1	1.8	3.6	4.5
1963-1964	5.0	4.8	5.7	3.9	5.2	6.0	2.6	6.7	5.0	5.7	3.8
1964-1965	4.8	6.5	5.9	3.8	5.0	6.4	1.3	7.6	2.6	4.1	4.2
1965-1966	6.8	6.7	6.1	5.2	6.2	8.4	3.5	8.9	7.7	8.8	5.9
1966-1967	4.6	6.1	3.8	4.3	7.1	5.4	0.5	7.5	2.4	4.8	5.0
1967-1968	6.2	7.2	6.2	6.3	6.7	8.1	3.6	8.2	4.3	4.3	4.5
1968-1969	6.9	6.6	7.0	5.6	7.5	7.2	3.8	11.9	8.1	5.7	6.9
1969-1970	4.2	5.3	4.4	2.6	5.6	6.3	2.7	6.2	1.9	2.4	4.4
1970-1971	2.9	5.0	2.7	3.4	2.7	3.4	0.9	3.2	0.3	2.2	7.6
1971-1972	4.9	5.8	4.2	5.9	4.3	3.8	5.2	8.0	2.5	3.1	4.4
1972-1973	4.8	4.9	5.5	6.6	5.8	5.8	5.0	4.2	1.4	0.2	5.0
1973-1974	(2.2)	(3.1)	(0.6)	(2.4)	(1.0)	(3.5)	(2.5)	0.4	1.6	(3.4)	1.2

Source: EEI

Exhibit V-4

REGIONAL PROJECTION
THOUSANDS OF CUSTOMERS AND GROWTH RATES
(for selected years)

	United States	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
1972 Customers	76,146	4,444	12,999	14,691	6,324	11,765	4,883	7,346	3,303	10,072	319
POP*	36.7	36.5	34.3	35.6	38.1	37.2	37.6	37.0	38.5	37.9	28.8
PCGR**	2.3	2.0	1.3	2.0	1.7	3.3	2.6	2.5	3.7	2.7	3.6
1975 Customers	81,505	4,691	13,519	15,559	6,658	12,945	5,266	7,898	3,681	10,933	355
POP*	37.6	37.3	34.7	36.3	39.2	39.2	39.8	38.2	40.7	38.7	30.5
PCGR**	2.5	2.0	1.5	2.2	2.0	3.4	2.8	2.7	3.8	2.9	3.6
1980 Customers	92,237	5,185	14,596	17,320	7,349	15,294	6,050	9,001	4,433	12,585	424
POP*	39.5	38.3	35.4	37.7	41.1	42.7	43.8	40.4	44.7	40.0	33.6
PCGR**	2.6	2.1	1.6	2.2	2.2	3.4	2.9	2.8	3.8	2.8	3.4
1985 Customers	104,711	5,751	15,832	19,349	8,163	18,062	6,982	10,273	5,339	14,460	500
POP*	41.7	39.3	36.0	39.1	43.1	46.6	48.2	42.7	49.1	41.4	37.1
PCGR**	2.4	2.0	1.5	2.1	2.1	3.2	2.8	2.5	3.6	2.6	3.1
1990 Customers	118,017	6,325	17,073	21,447	9,024	21,138	8,024	11,631	6,360	16,413	582
POP*	43.9	40.4	36.7	40.5	45.2	50.8	53.0	45.2	54.0	42.8	40.8
PCGR**	2.4	2.0	1.5	2.1	2.1	3.2	2.8	2.5	3.6	2.6	3.1

*Percentage of Population

**Period Compounded Growth Rate

Source: Census Bureau (Department of Commerce), EEI, TBS

Exhibit V-5

ELECTRIC CUSTOMERS AS A PERCENTAGE OF NATIONAL POPULATION
1960 - 1973
(percent)

	United States	New England	Middle Atlantic	East North Central	West North Central	Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
1960	32.71	34.43	32.81	32.76	34.17	30.74	30.69	32.58	31.48	33.04	23.40
1961	32.86	34.57	32.79	32.90	34.58	30.94	30.93	32.83	31.80	35.07	23.40
1962	33.01	34.45	32.90	33.09	34.85	31.19	31.40	32.83	31.98	35.12	23.47
1963	33.35	34.35	33.03	33.31	35.18	31.61	32.12	33.56	32.73	35.41	24.01
1964	33.57	34.31	33.15	33.45	35.45	31.65	32.24	33.91	32.95	35.76	24.59
1965	33.88	34.39	33.28	33.62	35.93	32.46	32.68	34.48	33.39	36.07	25.08
1966	34.22	34.71	33.53	33.79	36.25	33.08	33.30	34.79	33.69	36.35	25.62
1967	34.53	34.91	33.75	33.95	36.52	33.69	34.00	35.29	34.06	36.41	25.95
1968	34.97	35.36	33.87	34.38	36.93	34.30	34.69	35.86	34.61	36.86	26.60
1969	35.23	35.66	34.10	34.81	36.88	34.86	35.26	35.45	34.85	37.03	26.87
1970	35.67	36.08	34.29	35.08	37.27	35.60	36.09	35.92	35.75	37.41	27.57
1971	36.09	36.27	34.27	35.30	37.81	36.45	36.92	36.56	37.03	37.58	28.18
1972	36.73	36.56	34.34	35.62	38.16	37.25	37.67	37.03	38.51	37.96	28.83
1973	37.17	36.89	34.52	35.99	38.71	38.45	39.25	37.72	40.13	38.30	30.10

Sources: EEI, Census Bureau (Department of Commerce)

Exhibit V-6

REGIONAL HISTORICAL AND PROJECTED POPULATION

1960 - 1990

(thousands)

Year	United States	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
1960	179,974	10,531	34,270	36,291	15,424	26,091	12,073	17,010	6,916	29,497	871
1965	193,459	11,329	36,122	38,406	15,819	28,743	12,627	18,209	7,740	23,489	975
1970	203,180	11,847	37,153	40,253	16,319	30,671	12,805	19,322	8,284	25,454	1,072
1972	208,411	12,154	37,852	41,236	16,572	31,584	12,963	19,836	8,576	26,530	1,108
1975	216,553	12,630	38,928	42,757	16,961	33,007	13,206	20,634	9,034	28,231	1,165
1980	232,967	13,600	41,233	45,906	17,856	35,769	13,794	22,237	9,903	31,409	1,260
1985	251,272	14,687	43,869	49,474	18,914	38,752	14,477	24,008	10,855	34,887	1,349
1990	268,884	15,735	46,409	52,891	19,940	41,604	15,130	25,704	11,768	38,278	1,425

Source: Census Bureau (Department of Commerce)

Exhibit V-7

REGIONAL GENERATION NOT SOLD* TO ULTIMATE CUSTOMER

1969 - 1974

(percent)

Year	United States	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
1969	9.4	8.9	3.2	8.8	6.8	13.4	7.9	12.1	7.8	12.1	7.1
1970	9.2	9.3	5.3	7.9	8.3	11.3	6.6	12.1	13.0	10.6	7.9
1971	9.1	7.6	6.2	7.1	7.9	8.0	6.0	13.1	17.3	9.1	7.8
1972	9.7	6.3	6.2	5.4	9.2	15.4	8.4	12.7	20.9	7.1	8.8
1973	7.9	5.3	4.2	3.8	6.3	15.5	5.9	9.9	19.7	3.9	3.8
1974	8.8	3.4	2.6	3.4	9.4	17.0	3.7	11.6	22.7	7.5	4.7

*Percent line losses calculated from total Electric Utility Industry generation and total sales to ultimate customers (Includes "Energy Used by Producer", "Company Use and Free Service", and "Lost and Unaccounted For"

Source: EEI

Exhibit V-8

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: CAPACITY MIX BY PRIME MOVER
1975
(millions of kilowatts)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	196.2	0.5	21.3	68.9	16.2	43.6	28.8	5.6	9.6	1.5	0.2
Oil	72.1	12.3	21.7	3.4	0.5	18.3	0.5	5.9	0.7	8.1	0.7
Gas	89.5	0.1	1.7	3.0	7.7	4.0	2.7	48.5	6.1	15.2	0.5
Nuclear	40.7	4.9	8.0	9.2	2.0	8.3	2.4	1.5	0.3	4.1	0
Hydro	57.6	1.4	4.4	0.8	2.7	5.7	5.4	2.0	7.8	27.3	0.1
Pumped	8.5	0.9	1.8	1.4	0.4	1.1	0.2	0.3	0.3	2.2	0
Peaker	44.8	1.7	11.9	5.8	5.2	9.7	2.6	3.1	1.7	3.0	0.2
Other											
Total	509.7	21.9	70.8	92.4	34.7	90.8	42.6	66.9	26.6	61.3	1.7

Source: PTm (Electric Utilities)

Exhibit V-9

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: GENERATION MIX BY PRIME MOVER
1975

(billions of kilowatt hours)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	856.9	2.3	95.0	285.9	68.1	191.6	129.1	32.4	43.0	8.2	1.3
Oil	275.3	42.6	80.0	11.4	1.9	66.5	1.8	28.2	2.4	37.1	3.4
Gas	263.3	0.3	4.2	6.6	17.7	9.8	6.7	154.3	15.1	47.0	1.6
Nuclear	192.3	21.6	37.4	39.8	9.0	38.4	11.4	9.2	1.6	24.0	0
Hydro	250.0	5.2	16.8	3.0	9.7	21.6	21.0	10.0	29.9	132.3	0
Pumped	34.1	3.2	6.8	5.0	1.4	3.7	0.8	1.3	1.2	10.7	0
Peaker	36.6	1.3	9.5	4.4	3.9	7.7	2.1	3.3	1.4	2.9	0
Other											
Total	1908.2	76.6	249.6	356.0	111.5	339.2	172.8	238.7	94.5	262.2	7.1

Source: PTm (Electric Utilities)

Exhibit V-10

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: CAPACITY MIX BY PRIME MOVER

1980

(millions of kilowatts)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	287.1	0.6	24.8	80.4	30.0	55.1	36.0	21.3	20.5	4.0	0.2
Oil	85.8	12.5	22.8	5.8	2.2	17.0	1.5	10.0	1.0	18.2	0.7
Gas	48.1	0	0.3	0.5	2.0	2.1	0.8	41.5	4.8	4.3	0.4
Nuclear	79.7	6.7	13.0	14.8	2.0	17.9	10.9	6.2	0.3	8.0	0
Hydro	66.4	1.4	5.3	0.9	2.7	5.8	6.6	2.0	10.5	31.0	0.1
Pumped	11.8	0.9	1.8	1.4	0.4	1.6	1.7	0.5	0.5	3.0	0
Peaker	52.0	2.1	11.8	6.4	7.0	10.1	2.5	4.7	1.7	5.1	0.2
Other											
Total	631.0	24.2	79.9	110.3	46.2	109.6	60.0	86.2	39.3	73.6	1.6

Source: PTm (Electric Utilities)

Exhibit V-11

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: GENERATION MIX BY PRIME MOVER

1980

(billions of kilowatt hours)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	1303.2	3.2	122.1	353.9	114.3	280.8	133.0	132.0	76.2	23.9	1.9
Oil	319.6	50.9	86.6	19.1	4.6	67.1	3.4	40.8	2.8	70.3	4.7
Gas	142.4	0.1	0.8	1.2	4.1	5.7	1.6	134.6	9.5	13.7	2.1
Nuclear	404.1	36.5	66.5	67.0	8.4	95.6	41.5	38.6	1.3	48.8	0
Hydro	301.8	6.7	23.5	3.5	9.6	26.5	21.4	11.1	34.8	163.7	0.8
Pumped	49.4	4.0	7.5	5.3	1.4	7.0	5.1	2.4	1.6	15.2	0
Peaker	45.2	1.9	10.3	5.1	5.0	9.3	1.6	5.1	1.1	5.4	0.3
Other											
Total	2565.6	103.3	317.4	455.0	147.3	492.0	207.6	364.6	127.3	341.1	9.9

Source: PTm (Electric Utilities)

Exhibit V-12

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: CAPACITY MIX BY PRIME MOVER
1985

(millions of kilowatts)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	343.2	0.6	25.8	89.0	36.0	67.5	36.8	41.5	26.1	5.8	0.3
Oil	80.9	11.7	21.3	5.4	2.1	15.6	1.5	9.6	0.9	17.7	0.6
Gas	41.0	0	0.2	0.3	1.3	1.8	0.6	37.6	4.3	3.2	0.4
Nuclear	132.0	10.7	22.2	20.9	3.3	34.0	13.9	14.7	0.5	12.0	*
Hydro	73.5	1.4	6.1	0.9	2.7	6.4	6.9	2.0	12.4	34.4	0.2
* Pumped	16.3	1.7	1.8	2.5	0.4	2.5	2.1	0.8	0.6	4.0	0
Peaker	64.1	2.7	13.0	6.9	8.3	13.2	2.5	8.0	2.0	6.7	0.4
Other											
Total	751.0	28.8	90.3	125.9	54.1	141.0	64.3	114.2	46.8	83.7	1.9

Source: PTm (Electric Utilities)

Exhibit V-13

REGIONAL BASELINE SUMMARY TABLE
REGIONAL COMPARISON: GENERATION MIX BY PRIME MOVER
1985

(billions of kilowatt hours)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	1685.6	3.4	136.4	422.1	147.2	369.3	146.5	256.0	103.2	37.6	3.4
Oil	293.7	47.7	79.5	17.4	4.7	60.0	3.4	36.3	2.5	68.6	5.0
Gas	122.4	0.1	0.5	0.7	2.9	5.1	1.2	119.2	8.9	10.4	2.2
Nuclear	726.7	63.8	122.6	101.5	14.6	194.2	56.7	91.9	2.0	79.4	0.1
Hydro	359.1	7.4	29.0	3.8	10.1	31.6	24.1	11.0	43.8	196.5	1.7
Pumped	73.4	8.5	8.1	10.0	1.5	11.4	7.0	3.7	1.8	21.6	0
Peaker	60.6	2.8	12.4	5.9	6.3	13.1	1.8	8.7	1.4	7.7	0.6
Total	3321.4	133.6	388.5	561.4	187.3	684.6	240.7	526.7	163.5	421.8	13.2

Source: PTm (Electric Utilities)

Exhibit V-14

REGIONAL COAL CAPACITY BY IN-SERVICE YEAR FOR COMPLIANCE WITH CLEAN AIR ACT

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
New England	0.5	-	-	0.5
Middle Atlantic	20.8	1.5	4.5	26.8
East North Central	60.4	10.0	22.1	92.5
West North Central	16.9	2.2	17.3	36.4
South Atlantic	37.2	6.9	14.5	58.6
East South Central	29.5	1.7	7.6	38.8
West South Central	1.2	1.9	38.0	41.1
Mountain	8.9	5.5	15.8	30.2
Pacific	1.3	-	3.1	4.4
National Total	176.7	29.7	122.9	329.3

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975

Exhibit V-15

REGIONAL BASELINE PROJECTIONS

SUMMARY OF CUMULATIVE ADDITIONS (ADJUSTED FPC ANNOUNCEMENTS)

1975-1980

(millions of kilowatts)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	79.0	0	2.3	16.5	12.3	9.1	7.5	17.3	11.8	2.6	NO SCHEDULED ADDITIONS
Oil	17.6	2.2	4.1	3.9	0.2	5.5	0	0.6	0.3	1.0	
Gas	4.4	0	0	0	0	0	0	4.3	0	0	
Nuclear	48.0	2.6	6.8	6.6	0	11.9	9.5	4.7	0.3	6.0	
Hydro	11.4	0	1.0	0.1	0	0.8	1.2	0	3.9	4.3	
Pumped	3.5	0	0	0	0	0.8	1.5	0.2	0.2	0.9	
Peaker	13.6	0.5	0.9	1.1	2.6	1.7	1.2	2.3	0.1	2.8	
Other*	0	0	0	0	0	0	0	0	0	0	
Total	177.50	5.3	15.1	28.2	15.1	29.8	20.9	29.4	16.6	17.6	-

* *"Other" is included in Peaker category*

Source: PTm (Electric Utilities)

Exhibit V-16

REGIONAL BASELINE PROJECTIONS
SUMMARY OF CUMULATIVE ADDITIONS
1981-1985
(millions of kilowatts)

Prime Mover	National	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	Alaska & Hawaii
Coal	70.2	0	2.0	12.8	7.5	15.2	2.7	21.7	6.6	2.1	0.1
Oil	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Nuclear	52.3	4.0	9.2	6.1	1.4	16.0	3.1	8.6	0	4.1	0
Hydro	7.4	0	0.8	0	0	0.5	0.5	0	2.0	3.6	0.1
Pumped	4.5	1.0	0	1.0	0	1.0	0.5	0.3	0	0.9	0
Peaker	15.0	0.9	2.0	1.0	1.7	3.6	0	3.6	0.5	2.0	0.2
Other*											
Total	149.4	5.9	14.0	20.9	10.6	36.3	6.8	34.2	9.1	12.7	0.4

*"Other" is included in Peaker category

Source: PTu (Electric Utilities)

Exhibit V-17

REGIONAL BASELINE PROJECTIONS
SUMMARY OF ASSUMPTIONS
1975

Region	% of Capacity[1]		Fuel Price Index[2]			Non-Fuel O&M Index[3]	Capacity Factor[4] (%)
	Public	Private	Coal	Oil	Gas		
National	21.2	78.8	1.00	1.00	1.00	1.00	42.7
New England	3.1	96.9	1.59	1.02	2.67	1.55	39.6
Middle Atlantic	6.1	93.9	1.20	1.09	2.14	1.51	39.9
East North Central	5.9	94.1	0.98	0.99	1.52	1.07	43.2
West North Central	30.9	69.1	0.69	0.79	0.83	1.12	39.2
South Atlantic	7.8	92.2	1.30	0.95	1.20	0.83	42.2
East South Central	60.6	39.4	0.82	1.00	1.07	0.84	45.6
West South Central	17.6	82.4	0.31	0.99	0.87	0.56	41.5
Mountain	29.5	70.5	0.44	0.91	1.02	0.82	40.7
Pacific	49.7	50.3	0.63	1.02	1.20	1.02	49.3
Alaska & Hawaii	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	48.1

n.a. = not available

Sources: 1) EEI Data, 1973, adjusted for announced capacity additions.

2) Index relative to national average; EEI Data, 1974, adjusted to limits of ±20 percent of national average by 1985.

3) Index relative to national average; TBS survey of 47 electric utilities for EPA Rate Study.

4) PTm (Electric Utilities); based on announced and projected capacity additions.

Exhibit V-18

REGIONAL BASELINE PROJECTIONS
SUMMARY OF ASSUMPTIONS
1980

Region	% of Capacity[1]		Fuel Price Index[2]			Non-Fuel O&M Index[3]	Capacity Factor[4] (%)
	Public	Private	Coal	Oil	Gas		
National	21.2	78.8	1.00	1.00	1.00	1.00	46.4
New England	2.9	97.1	1.40	1.02	2.00	1.55	48.4
Middle Atlantic	6.4	93.6	1.20	1.09	1.70	1.51	45.1
East North Central	5.7	94.3	0.98	0.99	1.38	1.07	46.6
West North Central	32.5	67.5	0.74	0.84	0.83	1.12	39.5
South Atlantic	7.8	92.2	1.25	0.95	1.20	0.83	50.9
East South Central	61.8	38.2	0.82	1.00	1.07	0.84	39.3
West South Central	17.8	82.2	0.53	0.99	0.87	0.56	48.3
Mountain	30.2	69.8	0.60	0.91	1.02	0.82	36.8
Pacific	49.9	50.1	0.70	1.02	1.20	1.02	53.0
Alaska & Hawaii	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	70.5

n.a. = not available

Sources: 1) EEI Data, 1973, adjusted for announced capacity additions.

2) Index relative to national average; EEI Data, 1974, adjusted to limits of ±20 percent of national average by 1985.

3) Index relative to national average; TBS survey of 47 electric utilities for EPA Rate Study.

4) PTm (Electric Utilities); based on announced and projected capacity additions.

Exhibit V-19

REGIONAL BASELINE PROJECTIONS
SUMMARY OF ASSUMPTIONS
1985

Region	% of Capacity[1]		Fuel Price Index[2]			Non-Fuel O&M Index[3]	Capacity Factor[4] (%)
	Public	Private	Coal	Oil	Gas		
National	21.2	78.8	1.00	1.00	1.00	1.00	50.5
New England	2.8	97.2	1.20	1.02	1.20	1.55	52.4
Middle Atlantic	6.6	93.4	1.20	1.09	1.20	1.51	48.9
East North Central	5.7	94.3	0.98	0.99	1.20	1.07	50.6
West North Central	33.1	66.9	0.80	0.90	0.83	1.12	42.9
South Atlantic	7.8	92.2	1.20	0.95	1.20	0.83	55.1
East South Central	62.0	38.0	0.82	1.00	1.07	0.84	42.5
West South Central	17.8	82.2	0.80	0.99	0.87	0.56	52.5
Mountain	30.5	69.5	0.80	0.91	1.02	0.82	39.9
Pacific	50.2	49.8	0.80	1.02	1.20	1.02	57.4
Alaska & Hawaii	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	78.7

n.a. = not available

Sources:
1) EEI Data, 1973, adjusted for announced capacity additions.
2) Index relative to national average; EEI Data, 1974, adjusted to limits of ±20 percent of national average by 1985.
3) Index relative to national average; TBS survey of 47 electric utilities for EPA Rate Study.
4) PTm (Electric Utilities); based on announced and projected capacity additions.

APPENDIX V-A

NEW ENGLAND (REGION I)

Exhibit V-A-1	Capacity Report
Exhibit V-A-2	Financial Baseline Projections
Exhibit V-A-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-A-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-A-5	Impacts of Air & Water Pollution Regulations

Preceding page blank

Exhibit V-A-1

```
NEW ENGLAND - BASELINE WITH OIL AND GAS CONVERSIONS


                    TEMPLE BARKER AND SLOANE,INC.
                    PTM ELECTRIC UTILITY MODEL


                          CAPACITY REPORT

                KWH      NET KWH    12/31      TOTAL      TOTAL
                GEN      SALES      CAPACITY   ADDNS      RETIRED

  1974          74.6      69.3       19.5       1.5         .1
  1975          76.6      70.9       21.9       2.5         .1
  1976          82.1      76.0       21.9        .1         .1
  1977          87.0      80.5       21.8        .1         .1
  1978          92.2      85.3       22.2        .4         .1
  1979          97.6      90.4       23.2       1.0         .1
  1980         103.3      95.9       24.2       1.2         .1
  1981         108.8     101.0       25.2       1.2         .2
  1982         114.6     106.4       26.0       1.1         .2
  1983         120.6     112.1       27.1       1.2         .2
  1984         127.0     118.1       27.9       1.2         .2
  1985         133.6     124.3       28.8       1.2         .2
  1986         140.7     130.9       30.4       1.6         .2
  1987         148.0     137.8       31.9       1.7         .2
  1988         155.7     145.1       33.6       1.9         .2
  1989         163.8     152.7       35.3       2.0         .2
  1990         172.3     160.6       37.1       2.0         .2


                          CAPACITY REPORT

        TOTAL     COAL      OIL       GAS       NUCLEAR   HYDRO      PUMPED    IC/GT
        FOSSIL                                                      STORAGE

  1974   11.5      .5       10.8       .1         4.1      1.4          .9      1.6
  1975   13.0      .5       12.3       .1         4.9      1.4          .9      1.7
  1976   12.9      .5       12.2       .1         4.9      1.4          .9      1.8
  1977   12.8      .5       12.2       .1         4.9      1.4          .9      1.8
  1978   13.0      .6       12.4       .1         4.9      1.4          .9      2.0
  1979   13.0      .6       12.3       0          5.8      1.4          .9      2.1
  1980   13.1      .6       12.5       0          6.7      1.4          .9      2.1
  1981   13.0      .6       12.3       0          7.6      1.4         1.0      2.2
  1982   12.8      .6       12.2       0          8.3      1.4         1.2      2.3
  1983   12.7      .6       12.0       0          9.1      1.4         1.4      2.5
  1984   12.5      .6       11.9       0          9.9      1.4         1.5      2.6
  1985   12.3      .6       11.7       0         10.7      1.4         1.7      2.7
  1986   12.2      .6       11.5       0         11.9      1.4         2.0      2.9
  1987   12.0      .6       11.4       0         13.1      1.4         2.3      3.1
  1988   11.8      .6       11.2       0         14.4      1.4         2.6      3.4
  1989   11.6      .6       11.0       0         15.8      1.4         2.9      3.6
  1990   11.4      .6       10.9       0         17.2      1.4         3.2      3.9
```

Source: PTm (Electric Utilities)

Exhibit V-A-2

NEW ENGLAND - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS

(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	1.48	4.13	9.30
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	.39	1.64	2.68
EXTERNAL FINANCING			
TOTAL SINCE 1974	.66	2.77	6.74
OPERATING REVENUES			
TOTAL FOR YEAR	3.16	3.88	4.85
TOTAL SINCE 1974	3.16	21.00	43.32
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	1.95	2.38	2.69
TOTAL SINCE 1974	1.95	12.97	25.77
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	44.53	40.52	38.99
COVERAGE RATIO (EBIT TO INTEREST	3.13	3.59	3.39

Source: PTm (Electric Utilities)

Exhibit V-A-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

New England

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	-	-	-	-
TSP	-	-	-	-
Joint	-	-	-	-
Medium Sulfur Coal	-	-	-	-
Western Low Sulfur Coal	-	-	-	-
Blending				
SO_2	-	-	-	-
Joint	-	-	-	-
Precipitators	0.17	-	-	0.17
Subtotal	0.17	-	-	0.17
In Compliance	0.33	-	-	0.33
Conversion to Oil	-	-	-	-
Total	0.50	-	-	0.50

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-A-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

New England

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	1.2	6.9	4.6	2.2
After 316(a)	0	1.1	0.5	1.2
Entrainment	0	5.6	0.1	0.7
Chemical				
1977 Guidelines	0.3	0	2.3	0.4
1983 Guidelines	0.3	0	2.3	0.4
State Water Quality Standards	0	0	2.3	0

Source: EPA regional offices, 1975

Exhibit V-A-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

New England

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	89	$ .003	$ (.003)
Gas to Coal	-	-	-
Gas to Oil	75	.001	.006
Air Regulations			
Scrubbers			
SO_2	-	-	-
TSP	-	-	-
Joint	-	-	-
Medium Sulfur Coal	-	-	-
Western Low-Sulfur Coal	-	-	-
Blending			
SO_2	-	-	-
Joint	-	-	-
Precipitators	170	.003	*
Effluent Guidelines			
Fossil			
Thermal	1727	.046	.005
316 B	867	.030	.003
1977 Chemical	2639	.006	.001
1983 Chemical	2698	.002	*
Nuclear			
Thermal	1160	.030	.002
316 B	5651	.147	.011
Chemical	279	*	*
State Water Quality Standards			
Fossil Plants	2289	.086	.009
Nuclear Plants	-	-	-
Total[1]		$ .349	$ .033

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-B

MIDDLE ATLANTIC (REGION II)

Exhibit V-B-1	Capacity Report
Exhibit V-B-2	Financial Baseline Projections
Exhibit V-B-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-B-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-B-5	Impacts of Air & Water Pollution Regulations

Exhibit V-B-1

MIDDLE ATLANTIC - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE, INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	245.6	233.5	67.7	4.8	.3
1975	249.6	236.1	70.8	3.5	.4
1976	264.5	250.2	73.6	3.4	.4
1977	276.8	262.1	74.9	1.8	.4
1978	289.8	274.8	76.4	2.0	.4
1979	303.0	287.7	76.9	.9	.4
1980	317.4	301.8	79.9	3.5	.4
1981	330.5	314.6	82.3	3.0	.6
1982	344.2	327.8	84.3	2.7	.7
1983	358.4	341.6	86.3	2.7	.7
1984	373.2	355.8	88.4	2.8	.7
1985	388.5	370.6	90.3	2.8	.7
1986	404.5	386.1	93.9	4.4	.7
1987	421.2	402.2	97.9	4.6	.7
1988	438.5	418.9	101.8	4.7	.7
1989	456.4	436.2	105.8	4.8	.7
1990	475.0	454.2	110.4	5.1	.7

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	43.5	21.3	20.5	1.7	6.3	4.4	1.8	11.7
1975	44.7	21.3	21.7	1.7	8.0	4.4	1.8	11.9
1976	45.6	21.3	22.9	1.4	9.9	4.4	1.8	11.9
1977	46.9	22.0	23.8	1.1	9.9	4.4	1.8	11.9
1978	47.0	22.2	24.0	.8	11.3	4.4	1.8	11.9
1979	46.7	22.4	23.7	.6	12.2	4.4	1.8	11.8
1980	48.0	24.8	22.8	.3	13.0	5.3	1.8	11.8
1981	47.9	25.1	22.5	.3	15.0	5.6	1.8	12.0
1982	47.7	25.2	22.3	.3	16.8	5.7	1.8	12.3
1983	47.6	25.4	22.0	.2	18.6	5.8	1.8	12.5
1984	47.4	25.5	21.7	.2	20.4	6.0	1.8	12.8
1985	47.2	25.8	21.3	.2	22.2	6.1	1.8	13.0
1986	47.3	26.1	21.0	.1	25.1	6.3	1.8	13.4
1987	47.4	26.5	20.7	.1	28.1	6.6	1.8	14.0
1988	47.5	27.1	20.3	.1	31.3	6.8	1.8	14.4
1989	47.6	27.5	20.0	.1	34.5	7.0	1.8	14.9
1990	47.8	28.1	19.7	0	37.9	7.4	1.8	15.5

Source: PTm (Electric Utilities)

Exhibit V-B-2

MIDDLE ATLANTIC - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	2.37	11.32	24.16
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	2.81	4.24	7.16
EXTERNAL FINANCING			
TOTAL SINCE 1974	.03	5.12	14.95
OPERATING REVENUES			
TOTAL FOR YEAR	9.67	11.69	14.16
TOTAL SINCE 1974	9.67	64.45	130.20
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	6.05	7.45	8.63
TOTAL SINCE 1974	6.05	40.55	81.25
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	40.96	38.72	38.20
COVERAGE RATIO (EBIT TO INTEREST	2.88	2.78	2.77

Source: PTm (Electric Utilities)

Exhibit V-B-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

Middle Atlantic

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	0.7	-	-	0.7
TSP	-	-	-	-
Joint	3.9	1.5	2.0	7.4
Medium Sulfur Coal	-	-	-	-
Western Low Sulfur Coal	-	-	2.5	2.5
Blending				
SO_2	1.0	-	-	1.0
Joint	2.1	-	-	2.1
Precipitators	10.7	-	-	10.7
Subtotal	18.4	1.5	4.5	24.4
In Compliance	1.7	-	-	1.7
Conversion to Oil	0.7	-	-	0.7
Total	20.8	1.5	4.5	26.8

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-B-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

Middle Atlantic
In 1985
(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	6.0	18.1	9.9	9.6
After 316(a)	2.1	0	1.8	0
Entrainment	2.3	0.9	4.0	0.6
Chemical				
1977 Guidelines	6.3	11.3	41.2	4.2
1983 Guidelines	6.3	11.3	41.2	7.4
State Water Quality Standards	0.1	1.5	8.4	0.2

Source: EPA regional offices, 1975

Exhibit V-B-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS
ON
THE ELECTRIC UTILITY INDUSTRY
Middle Atlantic
1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	1975	$ .061	$(.076)
Gas to Coal	225	.018	.018
Gas to Oil	1050	.012	.089
Air Regulations			
Scrubbers			
SO_2	700	.056	.008
TSP	-	-	-
Joint	7449	.794	.108
Medium Sulfur Coal	-	-	-
Western Low-Sulfur Coal	2490	.191	.033
Blending			
SO_2	1000	.005	.004
Joint	2100	.014	.008
Precipitators	10700	.197	.020
Effluent Guidelines			
Fossil			
Thermal	1783	.085	.007
316 B	5003	.226	.020
1977 Chemical	45404	.122	.024
1983 Chemical	48607	.053	.003
Nuclear			
Thermal	2130	.134	.001
316 B	3245	.182	.006
Chemical	17574	.016	.004
State Water Quality Standards			
Fossil Plants	8588	.334	.034
Nuclear Plants	1636	.055	.003
Total[1]		$2.465	$.284

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-C

EAST NORTH CENTRAL (REGION III)

Exhibit V-C-1	Capacity Report
Exhibit V-C-2	Financial Baseline Projections
Exhibit V-C-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-C-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-C-5	Impacts of Air & Water Pollution Regulations

Exhibit V-C-1

EAST NORTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE, INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	348.5	324.4	86.0	6.3	.3
1975	356.0	320.6	92.4	6.9	.4
1976	378.1	348.8	95.3	3.5	.7
1977	395.8	366.1	98.4	3.7	.7
1978	414.5	384.5	103.4	5.7	.6
1979	433.7	403.4	106.6	3.8	.6
1980	455.0	423.9	110.3	4.4	.6
1981	474.6	442.6	113.9	4.5	1.0
1982	495.0	462.1	116.8	4.1	1.0
1983	516.3	482.3	119.8	4.1	1.1
1984	538.4	503.3	122.8	4.1	1.1
1985	561.4	525.1	125.9	4.1	1.1
1986	585.3	547.8	131.3	6.4	1.1
1987	610.2	571.4	136.9	6.6	1.1
1988	636.0	595.8	142.7	6.9	1.1
1989	662.8	621.2	148.7	7.2	1.1
1990	690.6	647.6	155.0	7.4	1.1

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	69.7	64.2	2.5	3.0	8.3	.8	1.4	5.8
1975	75.2	68.9	3.4	3.0	9.2	.8	1.4	5.8
1976	77.2	70.8	4.0	2.4	10.1	.8	1.4	5.8
1977	80.1	73.3	5.0	1.9	10.1	.9	1.4	5.9
1978	83.0	75.9	5.7	1.4	11.8	.9	1.4	6.3
1979	84.9	77.7	6.2	1.0	12.9	.9	1.4	6.5
1980	86.8	80.4	5.8	.5	14.8	.9	1.4	6.4
1981	88.6	82.4	5.7	.5	16.1	.9	1.7	6.6
1982	90.1	84.0	5.6	.4	17.3	.9	1.9	6.6
1983	91.6	85.7	5.6	.4	18.5	.9	2.1	6.7
1984	93.1	87.3	5.5	.3	19.7	.9	2.3	6.8
1985	94.7	89.0	5.4	.3	20.9	.9	2.5	6.9
1986	97.7	92.0	5.3	.2	22.7	.9	2.9	7.1
1987	100.8	95.3	5.3	.2	24.6	.9	3.2	7.4
1988	104.0	98.7	5.2	.1	26.6	.9	3.6	7.6
1989	107.4	102.2	5.1	.1	28.7	.9	3.9	7.8
1990	110.9	105.9	5.0	0	30.9	.9	4.3	8.0

Source: PTm (Electric Utilities)

Exhibit V-C-2

EAST NORTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	3.74	18.48	35.35
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	3.83	5.26	8.79
EXTERNAL FINANCING			
TOTAL SINCE 1974	2.70	11.42	23.40
OPERATING REVENUES			
TOTAL FOR YEAR	10.01	13.60	17.47
TOTAL SINCE 1974	10.01	71.00	150.49
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	5.34	7.75	10.03
TOTAL SINCE 1974	5.34	39.82	85.21
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	30.46	32.09	33.27
COVERAGE RATIO (EBIT TO INTEREST	3.20	3.04	2.87

Source: PTm (Electric Utilities)

Exhibit V-C-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

East North Central

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	10.0	-	-	10.0
TSP	3.2	-	-	3.2
Joint	8.1	4.1	8.7	20.9
Medium Sulfur Coal	9.5	4.5	-	14.0
Western Low Sulfur Coal	1.4	0.5	13.4	15.3
Blending				
SO_2	-	-	-	-
Joint	12.8	-	-	12.8
Precipitators	2.4	0.9	-	3.3
Subtotal	47.4	10.0	22.1	79.5
In Compliance	12.1	-	-	12.1
Conversion to Oil	0.9	-	-	0.9
Total	60.4	10.0	22.1	92.5

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-C-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

East North Central

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	0	0	2.4	0.3
After 316(a)	0	0	2.4	0.3
Entrainment	0	0	0	0
Chemical				
1977 Guidelines	0	0	0	0
1983 Guidelines	0	0	0	0
State Water Quality Standards	0	0	0	0

Source: EPA regional offices, 1975

Exhibit V-C-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

East North Central

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	1050	$.033	$(.033)
Gas to Coal	1500	.121	.087
Gas to Oil	675	.008	.043
Air Regulations			
Scrubbers			
SO_2	10000	.975	.103
TSP	3200	.065	.006
Joint	20912	2.228	.242
Medium Sulfur Coal	14007	.365	.100
Western Low-Sulfur Coal	15298	1.184	.171
Blending			
SO_2	-	-	-
Joint	12800	.088	.043
Precipitators	3285	.044	.004
Effluent Guidelines			
Fossil			
Thermal	2347	.093	.007
316 B	-	-	-
1977 Chemical	-	-	-
1983 Chemical	-	-	-
Nuclear			
Thermal	-	-	-
316 B	-	-	-
Chemical	-	-	-
State Water Quality Standards			
Fossil Plants	-	-	-
Nuclear Plants	-	-	-
Total[1]		$5.041	$.676

---

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-D

WEST NORTH CENTRAL (REGION IV)

Exhibit V-D-1	Capacity Report
Exhibit V-D-2	Financial Baseline Projections
Exhibit V-D-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-D-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-D-5	Impacts of Air & Water Pollution Regulations

Exhibit V-D-1

WEST NORTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	109.3	101.0	32.9	2.5	.1
1975	111.5	102.8	34.7	2.0	.1
1976	119.1	109.6	35.6	1.3	.3
1977	125.5	115.7	38.3	3.2	.4
1978	132.4	122.1	41.1	3.0	.2
1979	139.5	128.7	43.7	2.8	.2
1980	147.3	136.0	46.2	2.8	.2
1981	154.6	142.8	47.9	2.3	.4
1982	162.2	149.9	49.3	1.9	.5
1983	170.2	157.3	51.0	2.1	.5
1984	178.5	165.1	52.6	2.1	.5
1985	187.3	173.2	54.1	2.2	.5
1986	196.5	181.8	56.8	3.2	.5
1987	206.2	190.9	59.5	3.4	.6
1988	216.3	200.3	62.4	3.5	.6
1989	226.8	210.1	65.6	3.6	.6
1990	237.8	220.4	68.8	3.8	.6

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/BT
1974	23.1	14.8	.5	7.8	2.0	2.7	.4	4.7
1975	24.4	16.2	.5	7.7	2.0	2.7	.4	5.2
1976	25.2	17.8	.8	6.5	2.0	2.7	.4	5.3
1977	27.4	21.0	1.3	5.3	2.0	2.7	.4	5.8
1978	29.5	23.9	1.5	4.1	2.0	2.7	.4	6.5
1979	31.6	26.7	1.8	3.0	2.0	2.7	.4	7.0
1980	34.1	30.0	2.2	2.0	2.0	2.7	.4	7.0
1981	35.2	31.3	2.1	1.8	2.3	2.7	.4	7.3
1982	36.2	32.4	2.1	1.7	2.5	2.7	.4	7.5
1983	37.3	33.6	2.1	1.6	2.8	2.7	.4	7.8
1984	38.3	34.8	2.1	1.4	3.1	2.7	.4	8.1
1985	39.4	36.0	2.1	1.3	3.3	2.7	.4	8.3
1986	41.2	37.9	2.1	1.2	3.7	2.7	.4	8.8
1987	43.1	40.0	2.1	1.0	4.1	2.7	.4	9.2
1988	45.1	42.2	2.0	.9	4.5	2.7	.4	9.7
1989	47.2	44.4	2.0	.8	5.0	2.7	.4	10.3
1990	49.4	46.7	2.0	.6	5.5	2.7	.4	10.8

Source: PTm (Electric Utilities)

Exhibit V-D-2

WEST NORTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	1.02	8.47	15.64
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	1.43	2.09	3.61
EXTERNAL FINANCING			
TOTAL SINCE 1974	-.06	5.00	10.28
OPERATING REVENUES			
TOTAL FOR YEAR	3.24	4.67	6.19
TOTAL SINCE 1974	3.24	23.56	51.41
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	1.46	2.32	3.28
TOTAL SINCE 1974	1.46	11.42	25.83
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	31.57	34.31	35.72
COVERAGE RATIO (EBIT TO INTEREST	3.73	3.03	2.90

Source: PTm (Electric Utilities)

Exhibit V-D-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

West North Central
In 1985
(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	3.2	-	-	3.2
TSP	0.9	-	-	0.9
Joint	-	1.3	7.1	8.4
Medium Sulfur Coal	-	0.9	-	0.9
Western Low Sulfur Coal	-	-	10.2	10.2
Blending				
SO_2	4.8	-	-	4.8
Joint	-	-	-	-
Precipitators	5.5	-	-	5.5
Subtotal	14.4	2.2	17.3	33.9
In Compliance	2.5	-	-	2.5
Conversion to Oil	-	-	-	-
Total	16.9	2.2	17.3	36.4

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-D-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

West North Central

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	0.3	1.4	17.7	12.9
After 316(a)	0.3	1.4	7.3	4.4
Entrainment	*	*	0.4	3.0
Chemical				
1977 Guidelines	0.1	0.1	4.5	0.6
1983 Guidelines	0.1	0.1	4.5	1.5
State Water Quality Standards	0	0	0	0

Source: EPA regional offices, 1975

* less than 0.05

Exhibit V-D-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

West North Central

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	675	$ .021	$ (.024)
Gas to Coal	3075	.249	.133
Gas to Oil	2100	.024	.117
Air Regulations			
Scrubbers			
SO_2	3200	.275	.028
TSP	900	.016	.001
Joint	8360	.846	.078
Medium Sulfur Coal	884	.032	.004
Western Low-Sulfur Coal	10188	.781	.104
Blending			
SO_2	4800	.026	.013
Joint	-	-	-
Precipitators	5500	.101	.007
Effluent Guidelines			
Fossil			
Thermal	11769	.482	.023
316 B	3359	.115	.007
1977 Chemical	5090	.013	.002
1983 Chemical	6022	.007	*
Nuclear			
Thermal	1650	.059	.001
316 B	69	.004	*
Chemical	194		-
State Water Quality Standards			
Fossil Plants	-	-	-
Nuclear Plants	-	-	-
Total[1]		$2.754	$ .269

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities'

APPENDIX V-E

SOUTH ATLANTIC (REGION V)

Exhibit V-E-1	Capacity Report
Exhibit V-E-2	Financial Baseline Projections
Exhibit V-E-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-E-4	Nuclear and Fossil Capacity: Coverage for Complaince with Water Guidelines
Exhibit V-E-5	Impacts of Air & Water Pollution Regulations

Exhibit V-E-1

SOUTH ATLANTIC - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	324.5	283.1	83.3	8.1	.4
1975	339.2	294.2	90.8	7.9	.5
1976	369.2	320.1	96.0	5.8	.6
1977	396.6	344.4	99.8	4.5	.6
1978	426.1	370.7	102.1	2.8	.6
1979	457.4	398.7	105.6	4.1	.6
1980	492.0	429.4	109.6	4.6	.6
1981	525.7	459.2	115.9	7.1	.9
1982	561.7	491.0	121.7	6.9	1.0
1983	600.1	524.9	128.0	7.2	1.0
1984	641.0	561.0	134.1	7.4	1.0
1985	684.6	599.5	141.0	7.7	1.0
1986	731.0	640.4	150.4	10.7	1.0
1987	780.3	684.0	160.5	11.3	1.1
1988	832.9	730.4	171.4	12.0	1.1
1989	888.9	779.8	182.9	12.7	1.2
1990	948.4	832.3	195.1	13.4	1.3

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	62.6	41.3	17.1	4.1	6.0	5.0	.7	9.0
1975	66.0	43.6	18.3	4.0	8.3	5.7	1.1	9.7
1976	68.6	45.1	19.9	3.6	10.8	5.7	1.1	9.8
1977	70.5	46.6	20.7	3.2	12.5	5.7	1.3	9.8
1978	70.8	48.1	19.9	2.8	14.1	5.7	1.5	10.0
1979	72.4	50.2	19.8	2.4	15.8	5.7	1.6	10.1
1980	74.2	55.1	17.0	2.1	17.9	5.8	1.6	10.1
1981	76.3	57.6	16.7	2.0	21.1	5.9	1.8	10.8
1982	78.4	60.0	16.5	1.9	24.1	6.0	1.9	11.3
1983	80.5	62.4	16.2	1.9	27.3	6.1	2.1	12.0
1984	82.6	64.9	15.9	1.8	30.6	6.2	2.2	12.5
1985	84.9	67.5	15.6	1.8	34.0	6.4	2.5	13.2
1986	88.4	71.4	15.4	1.7	38.7	6.5	2.7	14.1
1987	92.2	75.5	15.1	1.6	43.6	6.7	2.9	15.1
1988	96.2	79.8	14.8	1.6	48.9	7.0	3.2	16.1
1989	100.4	84.5	14.4	1.5	54.5	7.2	3.5	17.3
1990	105.0	89.5	14.1	1.4	60.5	7.4	3.8	18.4

Source: PTm (Electric Utilities)

Exhibit V-E-2

SOUTH ATLANTIC - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	5.18	21.43	51.24
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	5.07	9.26	15.66
EXTERNAL FINANCING			
TOTAL SINCE 1974	-.52	12.51	39.09
OPERATING REVENUES			
TOTAL FOR YEAR	11.37	15.76	22.43
TOTAL SINCE 1974	11.37	81.89	179.59
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	5.75	8.42	11.19
TOTAL SINCE 1974	5.75	42.60	92.49
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	38.64	36.71	37.42
COVERAGE RATIO (EBIT TO INTEREST	3.22	2.89	2.73

Source: PTm (Electric Utilities)

Exhibit V-E-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

South Atlantic

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	3.2	-	-	3.2
TSP	1.4	-	-	1.4
Joint	2.1	0.5	13.6	16.2
Medium Sulfur Coal	7.0	4.1	-	11.1
Western Low Sulfur Coal	-	-	0.9	0.9
Blending				
SO_2	3.1	-	-	3.1
Joint	4.4	-	-	4.4
Precipitators	5.6	2.3	-	7.9
Subtotal	26.8	6.9	14.5	48.2
In Compliance	10.4	-	-	10.4
Conversion to Oil	-	-	-	-
Total	37.2	6.9	14.5	58.6

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-E-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

South Atlantic

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	5.2	27.9	16.7	25.0
After 316(a)	2.2	24.7	3.1	23.1
Entrainment	0	0.4	0.2	0
Chemical				
1977 Guidelines	5.6	10.8	62.6	10.1
1983 Guidelines	5.6	10.8	62.6	17.5
State Water Quality Standards	0.8	0	5.4	1.3

Source: EPA regional offices, 1975

Exhibit V-E-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

South Atlantic

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	5830	$ .181	$ (.143)
Gas to Coal	600	.049	.049
Gas to Oil	1050	.012	.079
Air Regulations			
Scrubbers			
SO_2	3200	.301	.039
TSP	1400	.028	.003
Joint	16174	1.710	.214
Medium Sulfur Coal	11153	.299	.090
Western Low-Sulfur Coal	927	.076	.013
Blending			
SO_2	3100	.019	.012
Joint	4400	.030	.017
Precipitators	7900	.103	.010
Effluent Guidelines			
Fossil			
Thermal	26162	.513	.096
316 B	184	.007	.001
1977 Chemical	72700	.158	.042
1983 Chemical	80094	.075	.006
Nuclear			
Thermal	26906	.843	.088
316 B	419	.013	*
Chemical	16419	.012	.004
State Water Quality Standards			
Fossil Plants	6713	.248	.022
Nuclear Plants	786	.041	.001
Total[1]		$4.477	$.657

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-F
EAST SOUTH CENTRAL (REGION VI)

Exhibit V-F-1	Capacity Report
Exhibit V-F-2	Financial Baseline Projections
Exhibit V-F-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-F-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-F-5	Impacts of Air & Water Pollution Regulations

Exhibit V-F-1

EAST SOUTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	171.8	159.4	40.7	2.5	.2
1975	172.8	159.3	42.6	2.3	.2
1976	181.1	167.0	46.5	4.0	.3
1977	187.3	173.0	50.0	3.9	.3
1978	193.8	179.5	52.8	3.0	.2
1979	200.4	185.9	56.2	3.7	.2
1980	207.6	192.9	60.0	4.0	.2
1981	213.8	198.9	61.1	1.6	.4
1982	220.3	205.1	61.9	1.3	.4
1983	226.9	211.4	62.7	1.3	.4
1984	233.7	217.8	63.5	1.3	.4
1985	240.7	224.5	64.3	1.3	.4
1986	248.0	231.4	66.2	2.4	.4
1987	255.5	238.6	68.3	2.5	.4
1988	263.2	245.9	70.3	2.5	.4
1989	271.1	253.4	72.5	2.6	.4
1990	279.2	261.0	74.4	2.7	.4

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	32.2	28.9	.5	2.7	1.4	5.5	.2	1.4
1975	32.0	28.8	.5	2.7	2.4	5.4	.2	2.6
1976	32.6	29.5	.7	2.4	4.3	5.4	1.6	2.6
1977	33.4	30.6	.9	1.9	7.1	5.4	1.6	2.5
1978	34.8	32.1	1.1	1.5	8.1	5.7	1.7	2.5
1979	37.2	34.7	1.3	1.2	9.0	5.8	1.7	2.5
1980	38.3	36.0	1.5	.8	10.9	6.6	1.7	2.5
1981	38.6	36.3	1.5	.7	11.7	6.6	1.7	2.5
1982	38.7	36.4	1.5	.7	12.2	6.6	1.9	2.5
1983	38.7	36.6	1.5	.7	12.8	6.8	1.9	2.5
1984	38.8	36.7	1.5	.7	13.4	6.8	2.0	2.5
1985	38.9	36.8	1.5	.6	13.9	6.9	2.1	2.5
1986	39.5	37.4	1.5	.5	15.0	7.0	2.2	2.5
1987	40.1	38.2	1.5	.5	16.1	7.1	2.4	2.6
1988	40.7	38.8	1.5	.4	17.3	7.2	2.5	2.6
1989	41.4	39.6	1.5	.4	18.4	7.4	2.7	2.6
1990	42.0	40.2	1.5	.4	19.6	7.4	2.8	2.6

Source: PTm (Electric Utilities)

Exhibit V-F-2

EAST SOUTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	1.50	15.18	21.50
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	4.22	2.02	3.69
EXTERNAL FINANCING			
TOTAL SINCE 1974	1.65	8.96	13.17
OPERATING REVENUES			
TOTAL FOR YEAR	3.60	5.25	5.70
TOTAL SINCE 1974	3.60	26.56	54.45
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	2.00	2.57	3.11
TOTAL SINCE 1974	2.00	13.82	28.25
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	22.57	27.22	25.41
COVERAGE RATIO (EBIT TO INTEREST	3.18	3.24	3.12

Source: PTm (Electric Utilities)

Exhibit V-F-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

East South Central

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	3.0	-	-	3.0
TSP	0.3	-	-	0.3
Joint	4.0	0.3	6.2	10.5
Medium Sulfur Coal	5.3	0.5	-	5.8
Western Low Sulfur Coal	-	-	1.4	1.4
Blending				
SO_2	9.0	-	-	9.0
Joint	-	-	-	-
Precipitators	5.1	0.9	-	6.0
Subtotal	26.7	1.7	7.6	36.0
In Compliance	2.8	-	-	2.8
Conversion to Oil	-	-	-	-
Total	29.5	1.7	7.6	38.8

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-F-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

East South Central

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	1.4	12.9	7.0	10.2
After 316(a)	1.4	12.9	6.6	10.2
Entrainment	0	0	0	0
Chemical				
1977 Guidelines	0	13.2	32.2	3.5
1983 Guidelines	0	13.2	32.2	10.0
State Water Quality Standards	0	0	5.9	1.4

Source: EPA regional offices, 1975

Exhibit V-F-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS
ON
THE ELECTRIC UTILITY INDUSTRY
East South Central
1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	-	$ -	$ -
Gas to Coal	650	.053	.027
Gas to Oil	1050	.012	.063
Air Regulations			
Scrubbers			
SO_2	3000	.273	.024
TSP	300	.006	*
Joint	10518	1.103	.096
Medium Sulfur Coal	5830	.134	.039
Western Low-Sulfur Coal	1384	.105	.014
Blending			
SO_2	9000	.050	.024
Joint	-	-	-
Precipitators	5985	.094	.006
Effluent Guidelines			
Fossil			
Thermal	16792	.590	.018
316 B	-	-	-
1977 Chemical	35700	.088	.016
1983 Chemical	42351	.054	.003
Nuclear			
Thermal	13900	.580	.010
316 B	-		-
Chemical	13181	.010	.002
State Water Quality Standards			
Fossil Plants	7297	.280	.014
Nuclear Plants	-	-	-
Total[1]		$3.352	$.267

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-G

WEST SOUTH CENTRAL (REGION VII)

Exhibit V-G-1	Capacity Report
Exhibit V-G-2	Financial Baseline Projections
Exhibit V-G-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-G-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-G-5	Impacts of Air & Water Pollution Regulations

Exhibit V-G-1

WEST SOUTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	231.2	206.2	62.1	6.3	.3
1975	238.7	215.4	66.9	5.2	.3
1976	260.3	235.7	67.4	2.0	1.5
1977	282.8	255.0	70.0	4.2	1.6
1978	308.2	276.1	74.1	4.7	.5
1979	335.3	298.6	79.6	6.1	.5
1980	364.6	323.5	86.2	7.2	.6
1981	392.9	348.0	91.5	6.4	1.0
1982	423.1	374.4	96.7	6.4	1.1
1983	455.3	402.7	102.3	6.8	1.1
1984	489.8	433.0	108.1	7.1	1.3
1985	526.7	465.5	114.2	7.5	1.3
1986	566.3	500.4	122.5	9.9	1.4
1987	608.6	537.8	131.7	10.5	1.5
1988	653.9	577.9	141.4	11.3	1.6
1989	702.3	620.8	151.6	12.0	1.6
1990	754.2	666.8	162.6	12.9	1.7

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/OT
1974	55.7	4.4	5.3	45.9	1.5	2.0	.3	2.6
1975	60.0	5.6	5.9	48.5	1.5	2.0	.3	3.1
1976	60.1	6.3	6.7	47.1	1.5	2.0	.3	3.5
1977	62.0	9.2	7.5	45.3	1.5	2.0	.3	4.2
1978	65.0	12.6	8.3	44.0	2.3	2.0	.3	4.5
1979	70.4	18.5	9.2	42.8	2.3	2.0	.3	4.6
1980	72.8	21.3	10.0	41.5	6.2	2.0	.5	4.7
1981	75.9	25.3	9.9	40.8	7.8	2.0	.5	5.3
1982	78.9	29.1	9.8	40.0	9.4	2.0	.5	5.9
1983	82.0	33.1	9.8	39.2	11.1	2.0	.6	6.6
1984	85.3	37.2	9.6	38.5	12.9	2.0	.6	7.3
1985	88.7	41.5	9.6	37.6	14.7	2.0	.8	8.0
1986	93.6	47.3	9.5	36.8	17.2	2.0	.8	8.9
1987	99.0	53.6	9.4	35.9	19.8	2.0	.9	10.0
1988	104.7	60.3	9.4	35.1	22.6	2.0	1.0	11.1
1989	110.8	67.3	9.3	34.1	25.6	2.0	1.0	12.2
1990	117.3	74.9	9.2	33.2	28.8	2.0	1.1	13.4

Source: PTm (Electric Utilities)

Exhibit V-G-2

WEST SOUTH CENTRAL - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	2.28	16.58	40.15
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	2.38	6.80	12.09
EXTERNAL FINANCING			
TOTAL SINCE 1974	1.76	16.38	37.81
OPERATING REVENUES			
TOTAL FOR YEAR	4.73	8.70	13.33
TOTAL SINCE 1974	4.73	38.83	93.06
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	2.46	4.49	5.63
TOTAL SINCE 1974	2.46	20.89	43.84
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	21.96	26.89	28.63
COVERAGE RATIO (EBIT TO INTEREST	3.50	2.76	2.74

Source: PTm (Electric Utilities)

Exhibit V-G-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

West South Central

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	-	-	-	-
TSP	-	-	-	-
Joint	-	0.6	9.2	9.8
Medium Sulfur Coal	-	1.3	-	1.3
Western Low Sulfur Coal	-	-	28.8	28.8
Blending				
SO_2	-	-	-	-
Joint	-	-	-	-
Precipitators	-	-	-	-
Subtotal	-	1.9	38.0	39.9
In Compliance	1.2	-	-	1.2
Conversion to Oil	-	-	-	-
Total	1.2	1.9	38.0	41.1

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-G-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

West South Central

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	0	12.6	17.9	36.6
After 316(a)	0	0	0	1.6
Entrainment	0	0	0	0
Chemical				
1977 Guidelines	0	1.5	17.9	7.2
1983 Guidelines	0	1.5	17.9	23.8
State Water Quality Standards	0	0	0	0

Source: EPA regional offices, 1975

Exhibit V-G-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

West South Central

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	-	$ -	$ -
Gas to Coal	-	-	-
Gas to Oil	4250	.048	.338
Air Regulations			
Scrubbers			
SO_2	-	-	-
TSP	-	-	-
Joint	9789	.998	.125
Medium Sulfur Coal	1325	.049	.008
Western Low-Sulfur Coal	28838	2.233	.443
Blending			
SO_2	-	-	-
Joint	-	-	-
Precipitators	-	-	-
Effluent Guidelines			
Fossil			
Thermal	1663	.030	.003
316 B	-	-	-
1977 Chemical	25170	.053	.012
1983 Chemical	41755	.058	.006
Nuclear			
Thermal	-	-	-
316 B	-	-	-
Chemical	1511	.001	*
State Water Quality Standards			
Fossil Plants	-	-	-
Nuclear Plants	-	-	-
Total[1]		$3.422	$.597

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: PTm (Electric Utilities)

APPENDIX V-H

MOUNTAIN (REGION VIII)

Exhibit V-H-1	Capacity Report
Exhibit V-H-2	Financial Baseline Projections
Exhibit V-H-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-H-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-H-5	Impacts of Air & Water Pollution Regulations

Exhibit V-H-1

MOUNTAIN - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	92.4	78.1	23.9	1.9	.1
1975	94.5	79.8	26.6	2.8	.1
1976	101.2	85.5	29.2	3.0	.3
1977	107.1	90.5	30.1	1.2	.3
1978	113.5	95.0	33.7	3.8	.1
1979	120.0	101.4	37.2	3.7	.2
1980	127.3	107.4	39.3	2.3	.2
1981	133.8	113.0	41.1	1.9	.3
1982	140.8	118.9	42.3	1.8	.3
1983	148.0	125.1	43.9	1.8	.3
1984	155.6	131.5	45.4	1.8	.3
1985	163.5	138.3	46.8	1.8	.3
1986	171.8	145.3	49.1	2.7	.4
1987	180.4	152.7	51.5	2.9	.4
1988	189.4	160.3	54.2	2.9	.4
1989	198.8	168.4	56.0	3.1	.4
1990	208.6	176.8	59.6	3.2	.4

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	15.2	8.4	.6	6.1	0	6.7	.3	1.7
1975	16.4	9.6	.7	6.1	.3	7.8	.3	1.8
1976	18.5	11.8	.9	5.8	.3	8.4	.3	1.7
1977	18.9	12.5	.9	5.4	.3	8.8	.4	1.7
1978	21.1	15.0	.9	5.2	.3	10.2	.4	1.7
1979	24.3	18.4	1.0	5.0	.3	10.5	.4	1.7
1980	26.3	20.5	1.0	4.8	.3	10.5	.5	1.7
1981	27.4	21.7	1.0	4.7	.4	10.9	.6	1.8
1982	28.3	22.7	1.0	4.6	.4	11.2	.6	1.8
1983	29.3	23.9	1.0	4.5	.4	11.7	.6	1.9
1984	30.3	24.9	1.0	4.5	.5	12.1	.6	1.9
1985	31.3	26.1	.9	4.3	.5	12.4	.6	2.0
1986	32.9	27.0	.9	4.2	.5	13.0	.6	2.1
1987	34.6	29.5	.9	4.1	.6	13.5	.6	2.2
1988	36.4	31.4	.9	4.0	.6	14.2	.6	2.4
1989	38.2	33.4	.9	[illegible]	.7	14.8	.7	2.4
1990	40.1	35.4	.9	1.8	.8	15.5	.7	2.5

Source: PTm (Electric Utilities)

Exhibit V-H-2

MOUNTAIN - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	1.68	10.23	16.73
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	2.41	2.05	3.54
EXTERNAL FINANCING			
TOTAL SINCE 1974	1.86	7.39	12.37
OPERATING REVENUES			
TOTAL FOR YEAR	2.55	3.91	5.02
TOTAL SINCE 1974	2.55	19.02	41.55
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	.86	1.40	2.04
TOTAL SINCE 1974	.86	6.68	15.28
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	31.95	36.41	36.29
COVERAGE RATIO (EBIT TO INTEREST	2.88	2.90	2.84

Source: PTm (Electric Utilities)

Exhibit V-H-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

Mountain

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	1.7	-	-	1.7
TSP	0.5	-	-	0.5
Joint	3.0	3.2	12.0	18.2
Medium Sulfur Coal	-	-	-	-
Western Low Sulfur Coal	-	1.7	3.8	5.5
Blending				
SO_2	-	-	-	-
Joint	-	-	-	-
Precipitators	2.3	0.5	-	2.8
Subtotal	7.5	5.5	15.8	28.8
In Compliance	1.4	-	-	1.4
Conversion to Oil	-	-	-	-
Total	8.9	5.5	15.8	30.2

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-H-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

Mountain

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	0	0	3.6	0
After 316(a)	0	0	0.9	0
Entrainment	0	0	0	0
Chemical				
1977 Guidelines	0	0	3.5	0
1983 Guidelines	0	0	3.5	0
State Water Quality Standards	0	0	0.2	0.3

Source: EPA regional offices, 1975

Exhibit V-H-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

Mountain

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	-	$ -	$ -
Gas to Coal	750	.061	.029
Gas to Oil	75	.001	.004
Air Regulations			
Scrubbers			
SO_2	1700	.146	.014
TSP	500	.010	.001
Joint	18191	1.863	.158
Medium Sulfur Coal	-	-	-
Western Low-Sulfur Coal	5507	.432	.042
Blending			
SO_2	-	-	-
Joint	-	-	-
Precipitators	2831	.042	.003
Effluent Guidelines			
Fossil			
Thermal	866	.035	.001
316 B	-	-	-
1977 Chemical	3526	.008	.002
1983 Chemical	3526	.003	*
Nuclear			
Thermal	-	-	-
316 B	-	-	-
Chemical	-	-	-
State Water Quality Standards			
Fossil Plants	550	.017	.001
Nuclear Plants	-	-	-
Total[1]		$2.555	$.222

*less than .0005

[1] Totals include impact of energy penalty but exclude impact of conversions.

Source: TBS (Electric Utilities)

APPENDIX V-I

PACIFIC (REGION IX)

Exhibit V-I-1	Capacity Report
Exhibit V-I-2	Financial Baseline Projections
Exhibit V-I-3	Coal Capacity: Coverage for Compliance with Clean Air Act
Exhibit V-I-4	Nuclear and Fossil Capacity: Coverage for Compliance with Water Guidelines
Exhibit V-I-5	Impacts of Air & Water Pollution Regulations

Exhibit V-I-1

PACIFIC - BASELINE WITH OIL AND GAS CONVERSIONS

TEMPLE BARKER AND SLOANE,INC.
PTM ELECTRIC UTILITY MODEL

CAPACITY REPORT

	KWH GEN	NET KWH SALES	12/31 CAPACITY	TOTAL ADDNS	TOTAL RETIRED
1974	259.9	239.2	58.0	4.3	.1
1975	262.2	242.8	61.3	3.2	.2
1976	278.5	258.0	63.7	3.2	.5
1977	293.0	271.0	67.5	4.3	.5
1978	308.5	284.8	70.7	3.3	.2
1979	324.1	299.0	71.7	1.2	.2
1980	341.1	314.5	73.6	2.3	.2
1981	356.1	328.3	75.7	2.8	.4
1982	371.6	342.6	77.8	2.5	.4
1983	387.8	357.5	79.8	2.5	.4
1984	404.5	372.9	81.8	2.5	.4
1985	421.8	389.0	83.7	2.5	.4
1986	439.4	405.3	87.3	4.0	.4
1987	457.7	422.3	90.8	4.1	.4
1988	476.6	439.9	94.5	4.2	.5
1989	496.2	458.1	98.6	4.4	.5
1990	516.5	477.0	102.6	4.8	.5

CAPACITY REPORT

	TOTAL FOSSIL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED STORAGE	IC/GT
1974	24.6	1.5	7.7	15.4	2.0	26.8	2.2	2.4
1975	24.7	1.5	8.1	15.2	4.1	27.3	2.2	3.0
1976	24.7	1.9	9.8	13.0	5.1	27.9	2.4	3.6
1977	25.1	2.5	12.1	10.5	6.1	29.7	2.4	4.2
1978	25.4	2.7	14.1	8.5	7.0	30.7	2.8	4.8
1979	25.7	3.3	16.1	6.4	7.0	31.0	2.9	5.1
1980	26.5	4.0	18.2	4.3	8.0	31.0	3.0	5.1
1981	26.6	4.4	18.1	4.1	8.8	31.6	3.2	5.5
1982	26.6	4.7	18.1	3.9	9.6	32.3	3.4	5.9
1983	26.6	5.0	17.9	3.6	10.4	33.1	3.6	6.1
1984	26.6	5.4	17.8	3.4	11.2	33.7	3.8	6.5
1985	26.6	5.8	17.7	3.2	12.0	34.4	4.0	6.7
1986	26.8	6.4	17.6	2.8	13.3	35.6	4.3	7.3
1987	27.1	7.0	17.5	2.6	14.6	36.7	4.6	7.8
1988	27.3	7.7	17.4	2.3	16.0	37.9	4.9	8.4
1989	27.6	8.3	17.3	2.1	17.5	39.2	5.3	9.0
1990	27.8	9.0	17.1	1.7	19.0	40.5	5.7	9.6

Source: PTm (Electric Utilities)

Exhibit V-I-2

PACIFIC - BASELINE WITH OIL AND GAS CONVERSIONS

FINANCIAL BASELINE PROJECTIONS
(BILLIONS OF 1975 DOLLARS)

	1975	1980	1985
CAPITAL EXPENDITURES (NET OF CWIP CHANGE)			
TOTAL SINCE 1974	2.29	12.22	22.48
CONSTRUCTION WORK IN PROGRESS			
END OF YEAR	3.48	3.36	5.79
EXTERNAL FINANCING			
TOTAL SINCE 1974	1.92	7.58	15.48
OPERATING REVENUES			
TOTAL FOR YEAR	4.81	6.64	7.87
TOTAL SINCE 1974	4.81	34.49	71.27
OPERATING AND MAINTENANCE EXPENSE			
TOTAL FOR YEAR	3.23	4.65	5.39
TOTAL SINCE 1974	3.23	23.50	48.90
CONSUMER CHARGES (MILLS PER KWH)			
AVERAGE FOR YEAR	19.80	21.12	20.23
COVERAGE RATIO (EBIT TO INTEREST	2.67	2.88	2.83

Source: PTm (Electric Utilities)

Exhibit V-I-3

COAL CAPACITY
COVERAGE FOR COMPLIANCE WITH CLEAN AIR ACT

Pacific

In 1985

(millions of kilowatts)

	In-Service Year			Total
	Pre-1974	1974-1976	After 1976	
Scrubbers				
SO_2	-	-	-	-
TSP	-	-	-	-
Joint	-	-	1.8	1.8
Medium Sulfur Coal	-	-	-	-
Western Low Sulfur Coal	-	-	1.3	1.3
Blending				
SO_2	-	-	-	-
Joint	-	-	-	-
Precipitators	-	-	-	-
Subtotal	-	-	3.1	3.1
In Compliance	1.3	-	-	1.3
Conversion to Oil	-	-	-	-
Total	1.3	-	3.1	4.4

Source: Sobotka & Co., Inc., unpublished data provided to EPA November 17, 1975.

Exhibit V-I-4

NUCLEAR AND FOSSIL CAPACITY COVERAGE FOR COMPLIANCE WITH WATER GUIDELINES

Pacific

In 1985

(millions of kilowatts)

	Nuclear Capacity		Fossil Capacity	
	Pre-1974	New	Pre-1974	New
Thermal				
Before 316(a)	0.7	3.0	7.7	0
After 316(a)	0.7	0.9	4.0	0
Entrainment	0	0	0	0
Chemical				
1977 Guidelines	0	0	0.1	0
1983 Guidelines	0	0	0.1	0
State Water Quality Standards	0	0	0	0

Source: EPA regional offices, 1975

Exhibit V-I-5

IMPACTS OF AIR AND WATER POLLUTION REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

Pacific

1975-1985

	Total Coverage 1975-1985	Cumulative Capital Expenditures For Pollution Control 1975-1985	Operating and Maintenance Expense For Pollution Control 1985
	megawatts	billions of 1975 dollars	
Capacity Conversions			
Oil to Coal	-	$ -	$ -
Gas to Coal	-	-	-
Gas to Oil	9750	.110	.925
Air Regulations			
Scrubbers			
SO_2	-	-	-
TSP	-	-	-
Joint	1823	.192	.026
Medium Sulfur Coal	-	-	-
Western Low-Sulfur Coal	1314	.103	.021
Blending			
SO_2	-	-	-
Joint	-	-	-
Precipitators	-	-	-
Effluent Guidelines			
Fossil			
Thermal	4010	.182	.009
316 B	-	-	-
1977 Chemical	74	*	*
1983 Chemical	74	*	*
Nuclear			
Thermal	1571	.073	.001
316 B	-	-	-
Chemical	-	-	-
State Water Quality Standards			
Fossil Plants	-	-	-
Nuclear Plants	-	-	-
Total[1]		$ .550	$ .058

*less than .0005

[1] Totals include impact of energy penalty buit exclude impact of conversions.

Source: [illegible]

ECONOMIC AND FINANCIAL IMPACTS OF FEDERAL AIR AND WATER POLLUTION CONTROLS ON THE ELECTRIC UTILITY INDUSTRY

VOLUME VI

SECONDARY IMPACTS

MAY 1976

VOLUME VI

TABLE OF CONTENTS

Page

List of Exhibits (VI-iii)

Chapter

1 INTRODUCTION AND OVERALL CONCLUSION VI-1
- Introduction VI-1
- Overall Conclusion VI-1

2 IMPACTS ON THE MAJOR USERS OF ELECTRICITY VI-4
- Methodology VI-5
- Major Assumptions VI-8
- Possible Refinement VI-10

3 IMPACTS UPON THE U.S. SULFUR INDUSTRY AND ADDITIONAL SECONDARY IMPACTS VI-12
- Sulfur Industry VI-12
- Other Areas VI-26

VOLUME VI

LIST OF EXHIBITS

Exhibits

VI-1 Calculations of PCE Impact on Ten Electricity-Intensive Industries

VI-2 Listing of Wholesale Price Indices Used

VI-3 Total Sulfur Production by Producers, 1964-1973

VI-4 Projections of Recovered Sulfuric Acid From Scrubbers, 1980 and 1985

Preceding page blank

CHAPTER 1

INTRODUCTION AND OVERALL CONCLUSION

INTRODUCTION

The purpose of this volume on Secondary Impacts is twofold: first, to assess the effect of higher rates on heavy users of electricity caused by utility expenditures for pollution control equipment, and second, to identify and analyze other areas likely to be affected as utilities comply with pollution control regulations. This analysis assumes that the increased costs of electricity will be passed on by major industrial users in the form of higher prices for their products and will not be absorbed in the form of reduced profit margins. The other areas of secondary impact focus largely on the effect on the sulfur industry of by-product sulfuric acid from regenerable scrubbers, but also include four other areas of less importance.

OVERALL CONCLUSION

The overall conclusion of this analysis is that secondary economic impacts of pollution control equipment in the electric utility industry will be very small--on major users of electricity and on other areas such as the sulfur industry.

Major Users

Secondary economic impacts on major users of electricity will be small by any measure. In the primary aluminum industry--the most electricity-intensive industry and the one where the effect will be greatest--higher costs for electricity brought about by utility expenditures for pollution control equipment will cause an increase in product price of 1.1 percent by 1985 (assuming an otherwise unchanged industry return on investment). The increase will exceed 0.5 percent in only four of the ten most electricity-intensive industries. The average for all industries will be less than 0.1 percent. In addition, these figures are based on conservative assumptions which may overstate the effects. In any event, when experienced over a ten-year period, even the 1.1 percent increase projected for primary aluminum prices appears quite modest in comparison with the 30 percent price increase that occurred between 1971 and 1974 (and the even larger increase since 1974).

Other Areas

The sulfur industry is the area most likely to be affected as utilities install pollution control equipment. However, the production of by-product sulfuric acid from regenerable scrubbers is likely to be only about 2.5 percent of industry production by 1985. An addition of that size--in an industry expected to grow at a 4 to 5 percent annual rate over the next decade--is unlikely to have major consequences for product prices or existing sulfur producers. In a similar fashion, as electric utilities install pollution control equipment, the economic impact on other areas will be small. Those industries producing pollution control equipment will of course be stimulated by the expenditure of $25 billion (1975 dollars) between 1975 and 1985. Purchases of limestone will be increased but are not expected to seriously affect limestone markets. Employment impacts will be mixed: jobs will increase for the construction and installation of pollution control equipment--40,000 to 50,000 construction jobs annually. In contrast, the price increases due to pollution control equipment for the electric utility industry and other industries may cause demand in these industries to be lower than the demand projected without pollution control expenditures. Therefore, total employment in these industries may be lower than otherwise projected. However, given the small price increase due to pollution control equipment, the net employment impact related to those impacts is likely to be slight both within the electric utility industry and others which will experience price increases.

* * *

Although there will be increased costs for electricity passed on to commercial and industrial customers, those increases will not cause significant changes in the economic structure of any individual industry. In fact, the impacts are sufficiently small even in the most electricity intensive industry than one can conclude that the overall effects of the pollution control expenditures will be diffused broadly throughout the entire economy.

In the two chapters that follow, the overall conclusion is discussed in more detail, together with an explanation of methodology, a description of assumptions, and relevant background.

CHAPTER 2

IMPACTS ON THE MAJOR USERS OF ELECTRICITY

The economic impact of the installation of pollution control equipment by electric utilities upon electricity-intensive industries will be small. By 1985 only four of the ten most electricity-intensive industries will experience product price increases greater than 0.5 percent attributable to pollution control-induced increases in electricity costs. These are as follows:

Category	Price Increase Due to Pollution Control Expenditures
Primary Aluminum	1.1%
Industrial Gases	0.9
Electrometallurgical Products	0.8
Alkalies and Chlorine	0.7

Thus, even in the most electricity-intensive of all industries--primary aluminum--the increase resulting from pollution control expenditures is only slightly more than 1 percent. For all manufacturing industries taken together, the impact of pollution control expenditures is less than 0.1 percent. The results of the analysis of the ten heaviest users of electricity are shown in Exhibit VI-1.

These increases are particularly small in light of the recent price increases experienced in nearly all industrial categories. In the ten categories examined, these price increases range from 30 percent to 146 percent over the three-year period from 1971 to 1974. The 30 percent increase in primary aluminum prices over this time period dwarfs the 1.1 percent increase attributable to pollution control expenditures by 1985.

Finally, the conclusions reached with respect to impacts on product prices of heavy electricity users are likely to be conservative. The analysis assumes that product prices in these industries will fully pass on electricity cost increases and that each industry will experience these increases at national average levels. In both cases, these assumptions contribute to the largest probable product cost impacts.

Most industries, particularly those which use large amounts of electricity or other forms of energy, are moving as rapidly as possible to less energy-intensive industrial processes. One forecaster[1] projects that aluminum will use 25 percent less electricity per ton produced in 1985 than in 1974. A similar forecast[2] for industrial gases estimates 13 percent reduction by 1980. This suggests that the future ratio of kilowatt-hours to units of output will fall. Since the analysis holds this factor constant, future cost increases may be less than those suggested above.

METHODOLOGY

The year 1971 is the most recent year for which industry-specific data are available at the level of detail needed for the secondary impact analysis. These data were extended to 1974 to assure consistency with the analysis carried out elsewhere in this report. These 1974 data provide a basis for estimating the 1985 impacts of utility expenditures for pollution control. The analysis shows the effects on industry prices that would have been experienced in 1974 if revenue increases necessitated by pollution control expenditures at that time were at the level anticipated for the year 1985. This methodology does not extrapolate product price and energy consumption data from 1974 to 1985 since such an effort is subject to large errors.

---

[1] *Industry Week*, November 18, 1974, p.14.

[2] *Conference Board, Energy Consumption in Manufacturing 1974, pp. 207, 209.*

The specific methodology consists of four major steps, each described below.

Selecting the Industries

The first step of the methodology was to identify and select the ten most electricity-intensive industries. Four-digit SIC codes were used to be sufficiently precise in industry definition: the use of broader categories would not have isolated electricity-intensive industries without including related categories which are not electricity-intensive. A total of 86 industries purchased more than one billion kilowatt-hours in 1971, and of this group ten industry categories were selected in which the cost of electricity constituted more than 3 percent of the value of that category's 1971 shipments, and in which more than six kilowatt-hours were consumed per dollar of value added in that industry category. This selection process resulted in the ten electricity-intensive industrial categories listed in Exhibit VI-1.

Extending Data to 1974

The second major step in the analytical methodology was to extend the available 1971 data to 1974, thereby making it consistent with the baseline year used throughout this report. This step first involved calculating for each industrial category the electricity costs as a percent of shipments for the year 1971 (the most recent year for which data were available). These percentages are shown as Column 1 in Exhibit VI-1. Then the percent change in the wholesale price index from 1971 to 1974 was obtained for each industry category, and the percent change in industrial electricity costs for the equivalent period was calculated. These percent changes are shown in Columns 5 and 6 in Exhibit VI-1. Finally, the percent changes were used to extend the 1971 electricity cost as a percent of shipments to a 1974 level, this figure being shown as Column 7 in the exhibit.

Including Pollution Control Expenditures

Volume III of this report concludes that electric utilities will require an increase in electric revenues of 6.7 percent by 1985 to cover the costs of adding pollution control equipment. This step of the methodology calculated electricity costs as a percent of shipments for the individual industries as if the utilities were already receiving the 6.7 percent increase in revenues in 1974 that will ultimately be required to recover the costs of installing pollution control equipment. These figures are derived simply by increasing 1974 electricity costs as a percent of shipments by 6.7 percent and are shown as Column 8 in Exhibit VI-1.

Calculating Pollution Control Expenditure Impacts

This final step in the methodology calculated the differential between Column 7, 1974 electricity costs as a percent of shipments for each of the industry categories without pollution control expenditures, and Column 8, the same item with pollution control rate increases added. The impact is thus expressed for each industry as the increase in price as a percent of shipments necessary to recover the increased costs of electricity due to the pollution control equipment added by the utilities. This impact is shown as Column 9 in Exhibit VI-1.

MAJOR ASSUMPTIONS

Implicit in the methodology and thus in the results of the analysis are four major assumptions. The assumptions are reasonable and were based on the data that were available. A conservative posture toward assumptions was taken where possible. The assumptions are described in some detail below.

Wholesale Price Indexes

For each of the ten industry categories, a wholesale price index was derived. In cases where the actual four-digit SIC code wholesale price index was available, this figure was used. In other cases the wholesale price index for a larger group of commodities had to be used. Exhibit VI-2 identifies the source and actual figures used for each of the ten industries.

Increases in Electricity Prices

The 1971-1974 increase in the price of electricity to all ten categories was assumed to be 56 percent. This is an all-industry figure based on data from the Department of Commerce and EEI Statistical Yearbooks for 1971 and 1974. Every industry in the country--including those ten electricity-intensive industries used in the analysis--obviously did not experience an identical increase in the cost of electricity during that particular period. Data for individual industries are simply not available, and the factors influencing actual increases in electricity costs varied considerably from industry to industry. For example, many industries purchasing large amounts of electricity enjoy a cost per kilowatt-hour much below national averages. Many aluminum producers have been purchasing electricity from hydroelectric sources and their historical costs have been low. In the future, however, these producers may have to purchase additional electricity from fossil-fired plants at much higher average costs. In a similar fashion, large industrial customers often have long-term contracts with electric utilities, and these contracts may alter the rate increases both recently experienced and expected in the future. Also, many large industrial users of electricity supply a substantial percentage of their own needs for electricity, and these costs may vary widely and increase at much different rates than do the costs of commercial electricity. Finally, substantial regional differences exist in the cost of commercial electricity, and this assumption ignores those differences. In sum, some of these factors will cause the costs of electricity to specific industry categories to increase more rapidly than national averages; others will cause the costs to increase less rapidly. Thus the assumption is that electricity costs increased 56 percent for all industries between 1971 and 1974.

Industrial Rate Increases

The third major assumption in the methodology is that industrial customers will experience the same rate increases as all other customers. Because industrial customers generally pay larger demand charges as a percent of total electric costs than do other categories of customers and because demand charges may increase more rapidly than other components of electricity rates due to high marginal costs per kilowatt, industrial customers may experience higher percentage increases in total electricity costs than do other customer categories. Data to analyze more specifically the impact of these factors are not available, and so the above-mentioned assumption was made. In a similar fashion, no attempt was made to distinguish regional differences in rate increases proportioned to industrial customers.

Cost Pass-Throughs

The last major assumption in the methodology is that increases in electricity costs will be passed through to product prices with neither additional nor reduced profits. Thus the return on investment of the various industry categories is assumed to remain unaffected by increases in the cost of electricity.

POSSIBLE REFINEMENT

It obviously would be possible to refine the analysis of secondary impacts on those industries which are heavy users of electricity. Assumptions could be narrowed, and figures made more specific. Several approaches to refining the secondary impact analysis are outlined below.

- More sophisticated analysis would be possible if actual 1974 data on a regional basis were available, particularly data on electricity cost differentials.
- The impact in terms of changed sales levels in each industry category could be made more accurate if estimates of price elasticity for these products were available.

- Those industries identified by this methodology as subject to the largest pollution control equipment impact--primary aluminum, industrial gases, and electrometallurgical products--could be analyzed in more detail by considering such factors as regional location, special contracts for electricity, and actual pollution control equipment cost impacts likely to be experienced by the utilities in that region of the country.

Given the relatively small secondary economic impact on even the industry which is the most intensive user of electricity, additional detail and analysis will not change the overall conclusion that the impact on electricity-intensive industries will be small.

CHAPTER 3

IMPACTS UPON THE U.S. SULFUR INDUSTRY AND ADDITIONAL SECONDARY IMPACTS

This chapter details the secondary impacts of electric utility pollution control equipment on areas other than those industrial customers for whom electricity costs are substantial. The first part deals with the impacts on the sulfur industry; the second part deals with the impacts on the early retirement of generating capacity, industries producing pollution control equipment, limestone consumption, and on overall employment.

SULFUR INDUSTRY

The economic impact of by-product sulfuric acid from regenerative scrubbers on the national markets for sulfur and sulfuric acid is likely to be minimal. Under the current provisions of the Clean Air Act, by-product sulfuric acid from scrubbers will comprise only 2.6 percent of total acid production by 1980, a figure that will decrease to 2.5 percent by 1985. Given the expectations for growth in the markets for sulfur and sulfuric acid--a 4 percent annual rate over the next ten years--and given expected retirements in U.S. acid capacity in the next decade, this additional production should be absorbed with little economic distortion.

Because of the recent problems in the U.S sulfur industry caused by the entry of by-product sulfur recovered from Western Canadian sour gas, great concern has been expressed over the impact on this industry of by-product sulfuric acid from regenerative scrubbers. For that reason, much attention has been paid to this subject, and it is presented in detail in the sections which follow.

Industry Perspective

Three points are critical to an understanding of the sulfur and sulfuric acid industries:

- 90 percent of the demand for sulfur is in the form of sulfuric acid--a form readily produced from elemental sulfur.
- Most of the basic supply is in the form of elemental sulfur and is transported in this form.
- For the most part, the sulfur producers and the acid manufacturers are different companies.

The two industries are closely interlaced in a supply-demand relationship in which their price structures and their consumption are proportionately related, as described below.

Supply

Historically, domestic production of sulfur in the United States has been derived from three sources: Frasch sulfur, recovered sulfur, and by-product sulfuric acid. Total sulfur production in 1973 was 10.9 million long tons, an increase of almost 160.0 percent during the previous decade. Sulfuric acid production was roughly three times that of sulfur since acid content is 30.7 percent elemental sulfur. A perspective of historical production is presented in Exhibit VI-3.

Frasch producers have historically dominated U.S. sulfur production; however, this dominance is slowly eroding with the steadily increasing production of recovered sulfur. In 1964 Frasch production accounted for 85.1 percent of U.S. production; by 1973 the share had declined to 69.6 percent. All of the 1973 amount was produced by 12 Frasch mines located in Louisiana and Texas. Five companies owned these mines: the Atlantic Richfield Company, Duval Corporation, Jefferson Lake Sulfur Company, Texasgulf, Inc., and the Freeport Minerals Company.

By 1973 recovery of sulfur by petroleum companies and by sour natural gas operations yielded 2.4 million long tons of sulfur--about equally split between them--or 22.1 percent of total U.S. production. Recovery sulfur production was largely dispersed between 132 facilities in 28 states, with the ten largest plants accounting for 37 percent of total output. Plant capacity in Texas, California, Florida, Louisiana, and Mississippi accounted for 51 percent of the production. The owners were: Exxon Company U.S.A., Getty Oil Company, Shell Oil Company, Standard Oil of California, and Standard Oil of Indiana. Production of refinery and sour gas recovery sulfur is expected to continue to increase because of two factors: increased U.S. dependence upon high sulfur, Middle East oil, and the increased development of dry sour natural gas associated with petroleum in the Jurassic Formations beneath Alabama, Mississippi, and Florida.

The final source of sulfur, by-product sulfuric acid, in 1973 amounted to 5 percent of domestic sulfur in all forms. It was produced at 18 plants in 12 states as a by-product of copper, lead, and zinc roasters and smelters. The five largest plants accounted for 57 percent of the production. The five largest producers are American Smelting and Refining Company, The Bunker Hill Company, Kennecott Copper Corporation, Phelps Dodge Corporation, and St. Joe Minerals Corporation. Together they accounted for 79 percent of the total by-product sulfuric acid production.

Acid Capacity

Sulfur capacity exists in the form of either mines, recovery devices, or smelters. Sulfuric acid capacity, on the other hand, consists of separate facilities in which production is either captive or externally marketed. In 1972, 23.4 million of the 39.0 million, or 60.0 percent of the total U.S. short ton sulfuric acid capacity, was for captive use; the remaining 40.0 percent was marketed through outside agents on the open market. Six states (California, Florida, Illinois, Louisiana, New Jersey, and Texas) contributed 58.0 percent of U.S. production capacity. Almost 70 percent of this six-state capacity, or 40.0 percent of total daily capacity, was located on the Gulf Coast.

The age of existing acid capacity may increase in importance as the production of by-product sulfuric acid from scrubbers increases. According to a study performed by ESSO Research & Engineering Company[1] in 1965, 40 percent of United States acid capacity was considered new (built 1952 and after), 40 percent was considered aging (built during World War II) and 20 percent was considered vintage (pre-World War II). Retirements of capacity, because of either significant age or the inability to meet air emission standards, may occur. The void in capacity left by these retirements, as well as an annual capacity addition rate of from 4 to 6 percent, will provide a major outlet for by-product acid.

---

[1] *Esso Research & Engineering Company, Long-Range Sulfur Supply & Demand Model, 1971.*

Demand

While 90 percent of U.S sulfur production is used to manufacture sulfuric acid, 54 percent of the manufactured acid is used to produce fertilizers. In fact, fertilizer production in 1970 consumed almost 15 million short tons of sulfuric acid as is shown in the following table:

USES FOR SULFURIC ACID
1970 Short Tons

End Use	Volume
Fertilizers	14,990
Petroleum Alkylation	2,400
Iron & Steel Production	800
Chemicals	
Aluminum	600
HF	880
T_1O_2	1,440
Alcohol	1,800
Other	5,730
Total	28,640

Source: Tennessee Valley Authority, Marketing H_2SO_4 From SO_2 Abatement Sources, PB-231 671, December 1973

The approximate distribution of sulfuric acid consumption was as follows:

Southern States (except Florida)	39%
Florida	30%
North Central	11%
Western	12%
North Eastern	8%

Traditionally, sulfuric acid has been the least expensive acid available and demand trends for both sulfur and sulfuric acid have tended generally to be inelastic. Consequently, reductions in acid price do not necessarily result in its increased marketability.

Annual demand growth for sulfur and sulfuric acid in the past has closely paralleled fertilizer consumption, which is expected to increase at an annual rate of from 4 to 6 percent.[2] A substantial increase in demand for these products would require the development of new markets. Such an increase is not likely because three potential new uses (as an agent in road building, rigid forms, and precast products) would consume only an additional 1 million short tons of sulfur per year[3]--not large compared to the current market size of over 28 million short tons.

---

[2] *TVA, Marketing H_2SO_4 from SO_2 Abatement Sources, PB-231 671, December 1973.*

[3] *EPA Sulfur Markets for Ohio Utilities, EOA 450/3-74-026, March 1974.*

Sulfur exports remained relatively stable from 1969 to 1973, averaging about 3.7 million long tons annually. Total imports, exports, and United States consumption are outlined in the following table. Imports of recovered sulfur from western Canadian sour gas fields and Frasch sulfur from Mexican mines constitute the bulk of U.S. imports. Mexican sources are imported primarily through Texas and Florida, while Canadian recovered sulfur is marketed on the West Coast and in the Midwest. The recent decline in imports is the result of anti-dumping duties imposed by the U.S. government on sulfur from Canada and Mexico, and a recent increase in domestic production.

HISTORICAL IMPORTS, EXPORTS, & U.S. CONSUMPTION FOR ELEMENTAL SULFUR
1964-1973

(thousand long tons)

Year	U.S. Consump.	Imports	Exports	Net Exports	Year End Stocks
1973	10,234	1,222	1,777	555	3,927
1972	9,854	1,188	1,852	664	3,796
1971	9,173	1,429	1,536	107	4,120
1970	9,227	1,667	1,443	(224)	3,829
1969	9,169	1,795	1,551	(244)	3,338
1968	9,007	1,712	1,602	(110)	2,790
1967	9,301	1,639	2,193	554	1,954
1966	9,145	1,674	2,373	699	2,704
1965	7,997	1,646	2,635	989	3,425
1964	7,260	1,582	1,928	346	4,226

Source: U.S. Department of Commerce, Bureau of Mines

Prices

Prices for sulfur and sulfuric acid differ widely among various locations. These differences in price are due to several factors:

- Transportation Costs: Costs vary widely depending upon the source of the sulfur, the location of the market, the form of the sulfur (S or H_2SO_4) and the means of transportation (rail, barge, etc.).
- Supply: Prices have tended to drop with the introduction of new supplies. New producers of recovered sulfur have marketed without regard to price (since their costs are far below the price) and have caused over-saturation of local markets.
- Manufacturing Costs: Due to the wide range of difficulty in extracting sulfur by the Frasch process, manufacturers are subject to production costs varying from $4 to $5/ton in rich sulfur deposits to $20 or more in areas where extraction requires many times more hot water injection per ton of sulfur produced.

Price fluctuations of sulfur greatly impact the producers of Frasch sulfur. This is because many Frasch producers have high production costs and, unlike secondary producers, have no co-product income available to meet rising transportation and manufacturing costs.

A historic perspective of sulfur and sulfuric acid prices is presented in the following table.

PRICES FOR SULFUR & SULFURIC ACID

1964-1973

	Approximate Delivery Price Gulf Ports $/Long Ton*	Price F.O.B. $/Long Ton	Cost of .307*** LT of Sulfur Gulf Port Price	List Price 100% Sulfuric Acid $/Short Ton*
1973	n.a.	18.6	n.a.	n.a.
1972	n.a.	17.4	n.a.	n.a.
1971	23.0	17.5	7.1	30.8
1970	25.5	23.7	7.8	30.8
1969	39.5	26.6	12.1	34.7
1968	46.0	40.3	14.1	34.6
1967	28.3	32.8	11.7	30.5
1966	30.8	26.1	9.4	26.9
1965	30.5	22.7	9.4	25.3
1964	28.5	20.0	8.8	23.8

n.a. = not available

**Esso Research & Engineering Company, Long Range Sulfur Supply & Demand Model, November 1971*

***Bureau of Mines historical statistics*

****.307 LT of Sulfur is required to produce 1 ST of 100% sulfuric acid.*

In the early 1970s, when recovered and by-product sulfur production reduced sulfur prices from the record levels experienced in the late 1960s, high-cost Frasch producers were forced to sell at a loss. Increased sales in 1974 and 1975[4] again have boosted some sulfur prices though whole industry price data are not available after 1973. Nonetheless, the price levels in the sulfur industry are unstable and changes in either supply or demand can have sizeable effects on price levels and thereby on the profitability of high-cost producers.

---

[4] *Oil Week, January 20, 1975, p. 36*

Impact Methodology

The analytical methodology developed to estimate the impact of by-product sulfuric acid from regenerative scrubbers on the U.S. markets for sulfur and sulfuric acid was based upon determining the amount of sulfuric acid produced by such pollution control equipment, then comparing that production with both the size and growth expectations in the total market. This methodology is described in the six steps which are listed below.

Scrubbed Capacity. The first step in determining the amount of by-product sulfuric acid that will be produced by regenerative scrubbers is to estimate the amount of generation capacity that will be scrubbed in 1980 and 1985. Under the current provisions of the Clean Air Act, EPA estimates that 29.1 million kw of new generation capacity will be scrubbed in 1980, and 63.5 million kw of new capacity by 1985. The estimate for retrofitting existing generation capacity remains at 54.4 million kw in both of these years. Therefore, it is estimated that 83.5 million kw of generation capacity will be scrubbed in 1980 and 117.9 million kw will be scrubbed by 1985, and these figures were used in this analysis.

Regenerable Scrubber Share. The second step in the analytical methodology is to estimate the portion of scrubbed generation capacity that will be fitted with regenerable scrubbers. The regenerable percentage will be affected by three factors: siting considerations, disposal costs, and capital and operating economics. Under present conditions, the high costs of these three variables, together with the still uncertain state of present scrubber technology, make the sludge disposal associated with non-regenerable scrubbers a more economically attractive alternative to utilities. Consequently, PEDCo Environmental Specialists estimate that only 15 percent of scrubbed capacity will be regenerable by 1980, this figure declining to 12 percent by 1985. This decrease in regenerable capacity's percentage of capacity from 1980 to 1985 results from the fact that new capacity installed during that period can be sited in a way that will permit the less expensive sludge disposal to be a far more attractive alternative.

Sulfur Content of Fuel. The third step involves making estimates of the sulfur content of the fuel burned by utilities. This is a key determinant of the final impact since the amount of sulfuric acid recovered from the regenerable scrubbers is proportional to the sulfur content of the fuel burned. PEDCo Environmental Specialists evaluated this factor and their findings indicate that a trend will develop to use lower sulfur fuels in regenerable systems. They suggest that the use of higher sulfur content fuels will require greater capital and operating investments to scrub stack gases, thereby increasing the likelihood that utilities will resort to sludge disposal if siting factors permit. With this fact in mind, a less sulfur-intensive fuel--one containing 2.1 percent sulfur--has been used in this analysis.

Asset Recovery. The fourth step in the methodology involves determining the amount of by-product sulfuric acid generated per kwh of capacity fitted with regenerable scrubbers. In a study prepared for EPA[5], PEDCo Environmental Specialists examined both regenerable and sludge disposal recovery systems and determined the amount of by-product acid recovered per kw for regenerable systems. They estimated that, with 2.1 percent sulfur fuel, 18.80 tons of sulfuric acid per million kw will be produced by scrubbers in retrofitted units for each hour of operation. For new generating units, the estimate is 18.17 tons. These data were used in the analysis as the basis for by-product acid recovered per scrubbed kwh.

---

[5] *PEDCo Environmental Specialists, Flue Gas Desulfurization Process Cost Assessment, May 6, 1975*

Capacity Factors. The recovery of by-product sulfuric acid obviously will depend upon the number of hours that the capacity with regenerable scrubbers is operated. This analysis used a capacity factor, derived from PEDCo Environmental Specialists and TBS data, of 60 percent for new capacity and 50 percent for older capacity. These figures reflect the typical pattern of a 60 percent capacity factor for the first 10 years of plant operation, declining by 1 percent annually thereafter.

Market Growth for Acid. The final step in the methodology involves estimating the expected growth in the market for sulfuric acid. An annual growth rate of 4 percent was used in the analysis. This figure is on the low side of the range of industry forecasts, thereby making the calculated impacts of pollution control equipment on the markets for sulfur and sulfuric acid larger than would be experienced in a more rapidly growing market. Sulfuric acid production in 1973 was 31.6 million short tons; with an annual growth rate of 4 percent, acid production will be 41.6 million short tons in 1980 and 50.6 million short tons in 1985.

Findings and Conclusions

Carrying the analytical methodology through to completion results in two key findings:

- By-product sulfuric acid from electric utility scrubbers will make up 2.6 percent of total acid production by 1980.
- Scrubber by-product acid will decrease to 2.5 percent of total acid production by 1985.

These key findings and the major data from which they are derived are presented in Exhibit VI-4.

In addition to the relatively small nature of the figures for by-product sulfuric acid, retirements of existing sulfuric acid capacity could alleviate the absorption of this incremental acid production even further. About 60 percent of U.S. sulfuric acid capacity is more than 30 years old and is thus considered aging or even older. To the extent that this capacity is retired during the next decade, the markets can absorb much more readily any by-product production.

A final consideration in assessing the relative impact of by-product sulfuric acid from scrubbers in utilities is the major uncertainties now facing the sulfur industry, each of which could create a much larger dislocation than that from utility-generated sulfuric acid. For instance, new uses for sulfur and sulfuric acid are likely but unknown, and the fertilizer market is likely to be vigorous but its growth rate could fluctuate violently. In a similar fashion, the government will determine import-export policy, and this final determination will have a decided effect on the markets for sulfur and sulfuric acid. An additional major factor affecting the outcome is the ultimate sulfur content of fuels used by utilities with regenerable scrubbers. Since sulfur content directly determines the quantity of acid by-product, an average content which varies from our estimate of 2.1 percent will alter the estimated impacts proportionately. Also the location and form in which sulfur will be recovered from these scrubber systems will help determine the final price economics and thus the impact of by-product sulfuric acid. A final unknown is the development of additional sources of sulfur or sulfuric acid, particularly scrubbers in other sectors of the economy such as the pulp and paper industry.

It is clear that by 1985, the 2.5 percent impact of by-product sulfuric acid generated by scrubbers in utilities will be one of the smaller items affecting the sulfur and sulfuric acid industries. The potential impacts of these other major uncertainties are substantially larger than those likely to result from the addition of utility scrubber by-product sulfuric acid to the existing market. Thus, given the quantity of by-product acid expected, the likely growth rate in the markets for sulfur and sulfuric acid, and these other major uncertainties, the additional production of by-product sulfuric acid from utility scrubbers should be absorbed with very little economic distortion.

Possible Refinement

Further detailed analysis obviously should result in a more precise forecast of the sulfur and sulfuric acid markets in 1985. Such an analysis would need to include the following items:

- A detailed forecast of demand for sulfur and related products by each major user industry based on a forecast for each of those industries
- A study of the existing and likely future producers--including all scrubber by-product sources--together with their respective cost economics
- The projected resolution of the major uncertainties discussed above
- Projections of the prices likely to result from the supply and demand conditions.

This analysis is beyond the scope of the present undertaking and requires data not currently available. The outcome of such an analysis would not be likely to affect the estimated impact in a major way. The increase of some 2.5 percent in sulfuric acid caused by EPA regulations on utilities is sufficiently small to have a negligible impact on the sulfur and sulfuric acid markets in 1980 or 1985.

OTHER AREAS

There are four other areas of secondary economic impact which merit consideration. Each is discussed briefly below.

Early Retirement of Generating Capacity

If the electric utilities find it economically infeasible to retrofit old generating plants with pollution control equipment, the pollution control requirements could cause some shutdowns of capacity and early retirements. These early retirements could cause employment dislocations or even reductions as old plants are shut down and their generating capacity replaced by new units requiring fewer employees per unit of output. In the absence of quantitative estimates of early retirements caused by pollution control equipment together with the employment levels of these older units, an accurate estimate of this impact is impossible. Available data and opinion, however, suggest that these early retirements will be small, or in those cases where early retirements do take place, the retired units will be replaced with new capacity equipped with pollution control equipment. Current best estimates indicate that this new capacity will maintain comparable employment levels per unit of capacity. Hence, the impact of early retirements of electric generating capacity should be small and thus have little economic effect.

Pollution Control Equipment Industries

A significant positive secondary impact will result from the need to design, build, and install pollution control equipment for the electric utility industry. As Volume III has shown, $25 billion (1975 dollars)--or $30.7 billion in current dollars--will be spent to produce and install this equipment over the next decade. Such demand may be met by expanding existing production capability, shifting other manufacturing facilities to the production of pollution control equipment, or actually adding new capacity to produce this equipment. Although a quantitative analysis of the production capability of U.S. industry to meet this demand is beyond the scope of the present study, expenditures averaging over $2 billion annually will have a stimulating economic impact. In addition, these levels of expenditures will not decrease as the retrofit program ends in the early 1980s, but will continue indefinitely at comparable levels as the utility industry continues to add to its capacity. The employment impact is analyzed separately below.

Limestone Consumption

The consumption of limestone by pollution control equipment is an additional area of secondary impact. Estimates of relatively small limestone consumption by pollution control equipment in 1985, together with limestone's wide availability and its current large and easily expanded production capability, indicate that demand will not seriously affect limestone markets one way or another. Several studies by PEDCo Environmental Specialists of limestone availability and price economics of specific plant sites have indicated, however, that the situation experiences considerable regional differences. Therefore, it is possible that national figures could obscure regional impacts and difficulties.

Overall Employment

The secondary impact of pollution control expenditures on employment will be mixed. There will be increases in the industries which produce and install pollution control equipment. However, there will probably be offsetting decreases in the electric utility industry and other industries in which price levels will rise as a result of these pollution control costs.

The present experience in the electric utility industry is that approximately 20 to 25 building trades jobs are supported by each $1 million of expenditures for new plant and equipment. Assuming that that ratio will also apply to the construction and installation of pollution control equipment, a rough calculation would suggest that the average annual expenditures of approximately $2.0 billion (1975 dollars) in the 1975-1985 period would support 40,000 to 50,000 jobs in the building trades.

On the opposite side of the coin, there will probably be employment declines as a result of demand elasticities in the industries discussed above. However slight the price increases may be in those industries, they and the industries which buy their products will undoubtedly experience some reductions in demand, and therefore will cut back their work forces, as a result of the increased prices of electricity. While the magnitude of this effect cannot be readily quantified, the employment declines can be expected to be diffused among many industries because, as the analysis above concluded, no single industry should experience more than a 1.1 percent price increase. A rigorous analysis of employment impacts would require very detailed data on industry price elasticities, a complete input-output methodology, and heroic assumptions.

The overall employment impact will be small in any case when viewed in the context of the national economy with a total civilian U.S. labor force of approximately 90 million persons.

Exhibit VI-1

CALCULATION OF PCE* IMPACT ON TEN ELECTRICITY-INTENSIVE INDUSTRIES

SIC Code	Industry	1971				1971-1974 % Change In:		1974 Electricity Cost as % of Shipments		PCE Impact: % Increase In Price (Value of Shipments) Due to PCE
		Electricity Cost as % of Shipments	kwh per $ Value Added	Total kwh (millions) Purchased and Net Generated	Mills per kwh Purchased	Wholesale Price Index	Costs of Electricity to Industrial Customers	Without PCE	With PCE at 1985 Levels	
		1	2	3	4	5	6	7	8	9
2611	Pulp Mills	3.8	13.1	4,815	6.6	94.5	56	3.1	3.3	0.2
2621	Paper Mills	4.0	11.3	29,471	8.0	30.2	56	4.8	5.1	0.3
2631	Paperboard Mills	4.1	10.4	17,125	8.5	48.6	56	4.3	4.6	0.3
2812	Alkalies & Chlorine	9.6	30.6	11,044	5.9	48.7	56	10.1	10.8	0.7
2813	Industrial Gases	12.4	21.5	10,291	8.0	48.7	56	13.0	13.9	0.9
2819	Industrial Inorganic Chemicals, n.e.c.	6.7	17.2	40,430	7.2	48.7	56	7.0	7.3	0.5
3241	Cement, Hydraulic	5.4	9.3	9,122	9.3	29.9	56	6.5	6.9	0.4
3313	Electrometallurgical Products	10.2	39.3	9,582	5.9	32.2	56	12.1	12.9	0.8
3334	Primary Aluminum	13.9	74.8	53,688	4.3	30.2	56	16.7	17.8	1.1
3339	Primary Nonferrous Metals, n.e.c.	3.7	21.8	3,790	4.9	146.5	56	2.3	2.5	0.2
	All Industries	0.9	1.9	597,441	9.9	17.9	56	1.20	1.28	0.08

Pollution Control Expenditures

Source: U.S. Department of Commerce, 1971 Annual Survey of Manufactures, 1972 Census of Manufactures: Fuels and Electric Energy Consumer (Supplement), Survey of Current Business; Edison Electric Institute, Statistical Yearbooks (1971 and 1974); and TBS calculations

Preceding page blank

Exhibit VI-2

LISTING OF WHOLESALE PRICE INDICES USED

SIC Code	Name	Wholesale Price Index Used	1971 Level	1974 Level	1971-1974* Percentage Increase
2611	Pulp Mills	Wood Pulp BLS Category 09-11	112.0	217.8	94.5%
2621	Paper Mills	Paper BLS Category 09-13	114.1	148.6	30.2%
2631	Paperboard Mills	Paperboard BLS category 09-14	102.4	152.2	48.6%
2812	Alkalies & Chlorine	Industrial Chemicals BLS Category 06-1	102.0	151.7	48.7%
2813	Industrial Gases	Industrial Chemicals BLS Category 06-1	102.0	151.7	48.7%
2819	Industrial Inorganic Chemicals, n.e.c.	Industrial Chemicals BLS Category 06-1	102.0	151.7	48.7%
3241	Cement, Hydraulic	Cement, Hydraulic SIC 3241	124.6	161.9	29.9%
3313	Electrometallurgical Products	Miscellaneous Metal Products BLS Category 10-8	119.0	157.3	32.2%
3334	Primary Aluminum	Primary Aluminum SIC 3334	115.9	150.9	30.2%
3339	Primary Nonferrous Metals, n.e.c.	Primary Nonferrous metals, n.e.c. SIC 3339	112.8	278.0	146.5%
	All Industries	Private Business - nonfarm	134.9	159.1	17.9%

*Column 5, Exhibit VI-1

Source: Monthly Labor Review, U.S. Department of Labor, Bureau of Labor Statistics
Survey of Current Business, U.S. Department of Commerce, Bureau of Economic Analysis

Exhibit VI-3

TOTAL SULFUR PRODUCTION BY PRODUCERS

1964 - 1973

(million short tons)

YEAR	WORLD SULFUR PRODUCTION	U.S. SULFUR PRODUCTION	FRASCH SULFUR	RECOVERED ELEMENTAL SULFUR	BY-PRODUCT SULFURIC ACID* PRODUCED AT CU, ZN & PB PLANTS	PERCENT FRASCH	NEW SULFURIC ACID PRODUCTION
1973	31.6	10.9	7.6	2.4	.600	69.6	NA
1972	28.2	10.2	7.3	2.0	.546	71.3	31.0
1971	24.8	9.6	7.0	1.6	.518	73.3	29.4
1970	22.2	9.6	7.1	1.5	.537	74.1	NA
1969	20.8	9.5	7.1	1.4	NA	74.9	27.4
1968	19.5	9.7	7.5	1.4	NA	76.6	27.4
1967	17.9	9.1	7.0	1.3	NA	76.8	27.7
1966	16.4	9.2	7.0	1.2	NA	76.5	27.4
1965	15.3	8.2	NA	NA	NA	NA	23.8
1964	31.9	7.1	6.0	1.0	NA	85.1	22.0

NA = Not Available

**Sulfuric acid is 30.7 percent elemental sulfur. The elemental sulfur content is illustrated in this chart. To determine short ton production by by-product sulfuric acid, multiply above amount by 3.26.*

Source: Department of Commerce; Bureau of Mines, TVA, ESSO Research & Engineering Company

Exhibit VI-4

PROJECTIONS OF RECOVERED
SULFURIC ACID FROM SCRUBBERS

1980 and 1985

	1980			1985		
Type Capacity Fitted	Total Scrubbed Capacity (million kw)	Sulfuric Acid (thousand short tons)	% of Projected Total Acid Production	Total Scrubbed Capacity (million kw)	Sulfuric Acid (thousand short tons)	% of Projected Total Acid Production
Total	83.5	1089.2	2.62	117.9	1278.3	2.53
Existing Retrofit	54.4	671.9	1.62	54.4	671.9	1.33
New	29.1	417.3	1.00	63.5	606.4	1.20

Source: PEDCo Environmental Specialists; TBS